FINAL PROJECT REPORT

TRANSMISSION BENEFIT QUANTIFICATION, COST ALLOCATION AND COST RECOVERY

Prepared for CIEE By:

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CERTS
CONSORTIUM FOR ELECTRIC RELIABILITY TECHNOLOGY SOLUTIONS

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The PIER Research Manager for this project was Virgil Rose. A Technical Advisory Committee (TAC) was established to review research results and offer guidance to the research team. Two in-person TAC meetings were held along with other written and oral communications as needed and appropriate. The Technical Advisory Committee consisted of:

- Dede Hapner, Vice President, FERC and ISO Relations, Pacific Gas & Electric.
- Les Starck, Director of T & D Business Unit, Southern California Edison.
- Caroline Winn, Director of T&D Asset Management, San Diego Gas & Electric.
- Sean Gallagher, Director of Energy Division, California Public Utilities Commission.
- Steve Ellenbecker, Energy Advisor to Wyoming Governor Freudenthal.
- Jim Bushnell, Research Director, UC Energy Institute.

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- Project Management and Outreach – Joe Eto and Vikram Budhraja.
- Review of Technologies – John Ballance, Jim Dyer, and Jim Terpening.
- Industry and Regulatory Changes – Vikram Budhraja, John Ballance and Jim Dyer.
- Review of other Regions and Industries – Alison Silverstein.
- CA ISO Transmission Planning Process and Comparison of ISO's -- John Ballance and Jim Dyer.
- Benefit Quantification, Cost Allocation, Cost Recovery – Vikram Budhraja and Fereidoun (Fred) Mobasheri.

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by binging environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

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For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

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Abstract

This project was commissioned to perform a scoping study to understand transmission benefit quantification, cost allocation, cost recovery, and project approval processes with a particular focus on recommending new methods for improved benefit quantification and cost allocation that better fits the new electric industry structure and planning environment.

Research goals and objectives included:

1. Review methodologies currently being used for transmission project quantification.
2. Review and summarize benefit analysis that have been carried out for some recent transmission projects in California.
3. Present and summarize research results to improve benefit quantification methods for new transmission projects.
4. Outline approaches to apply improved benefit quantification method to: evaluate project cost effectiveness, allocate project costs among participants, and develop framework for cost recovery.

Key conclusions and research recommendations are:

- Use a social rate of discount to calculate the present worth of benefits of a new major regional transmission projects rather than utility cost of capital to recognize the public good and long life attributes of transmission.
- Calculate explicitly the fuel diversity benefit from integration of large renewable resources.
- Utilize a stakeholder consensus approach, such as Delphi method, to assign value to some of the strategic benefits such as risk mitigation against extreme reliability and market volatility events.
- Initiate research into (a) dynamic analysis to evaluate the impact on generation expansion in exporting regions (b) resource portfolios analysis to assess performance of different combination of demand response, renewables and fuel based generation, transmission and energy conservation programs, and (c) quantification of extreme event benefits (Insurance Value) in terms of reliability and reduced market volatility to estimate the benefits from the low probability/high impact events.

Keywords: Benefit Quantification, Cost Allocation, Transmission Project Benefits and Cost Allocation, Cost Recovery, Transmission Planning, Strategic Benefits of Transmission Projects, Social Rate of Discount, Cost Allocation, Cost Recovery

Executive Summary

This project was commissioned to perform a scoping study to understand transmission benefit quantification, cost allocation, cost recovery and project approval processes with a particular focus on recommending new methods for improved benefit quantification and cost allocation that better fits the new electric industry structure and planning environment.

There is general policy consensus on the need for new transmission projects to advance the policy objectives of renewables integration, reliability management, efficient market operations, interconnect new load and generators, reduce transmission congestion and bottlenecks, and expand access to regional power markets. Historically, major transmission projects were sponsored and owned by utilities and generally proposed as part of new power plant development by integrated utilities.

This landscape has changed with the separation of generation and transmission assets and separation of transmission operations from ownership by shifting the responsibility of transmission operations from utilities to Independent System Operators/Regional Transmission Operators (ISOs/RTOs) such as California Independent System Operator (CA ISO). These changes in industry structure, operations, and planning impact how new transmission projects are planned, evaluated and approved. Approval of proposed major regional transmission projects in this new environment has proved to be challenging, witness the difficulty in moving forward with several California based projects such as the Palo-Verde Devers No.2 line, Rainbow-Valley line and others. This difficulty has brought into focus the need for research on benefit quantification and cost allocation methods to help with the approval of major regional transmission projects.

Utility efforts to develop new transmission projects that are local in nature, address well documented reliability needs, and are required for interconnecting new load or generation are generally supported and have been gaining regulatory approvals and stakeholder support. However, major regional transmission projects that involve multiple jurisdictions and utilities and are needed for integrating remote resources, reducing costs, improving market operations, providing long term strategic benefits and improving operating flexibility, don't have a clear path forward. For a major regional transmission project involving multiple jurisdictions and utilities to go forward, there needs to be a consensus on benefits, costs, and allocation of benefits and costs that can be embraced by stakeholders and policy makers.

The research focus was to identify different benefit streams, outline methodologies to quantify benefits including strategic benefits that have in the past been handled qualitatively, and outline approaches for assessment of benefits and assignment of benefits that could be factored into project cost allocation and cost recovery decisions of major transmission projects that may involve multiple utilities and regulatory jurisdictions. The research is not directed at seeking consensus among stakeholders or recommending cost allocation methodology for any specific project but to serve as an analytic framework that could be adapted for use for major transmission projects.

As part of the research, a review of other industries, planning methods, technology and regulatory issues was also conducted. Key findings are summarized below:

- Planning Process—A consistent, transparent and predictable planning process is critical to gain stakeholder and regulatory support. Traditionally, this was utility initiated and managed. Utilities continue to play a key technical role in transmission planning. With the regulatory and structural changes in the industry, the planning coordination within the footprint of ISOs and RTOs has shifted from utilities to ISOs and RTOs with stakeholder participation and hence benefit quantification, cost allocation and cost recovery methods that worked in the past may not be applicable.
- Lessons from other industries—Electric transmission networks differ in some key respects when compared to other networks such as gas and telecommunications. The most important difference is property rights—electric networks are operated as open access networks with financial rights but not physical property rights. Transmission networks are a public good in that transmission owners cannot reserve use of transmission for their exclusive use. The exception is non-network facilities such as DC lines, radial lines, and point to point links. This finding was utilized to recommend use of social rate of discount to estimate present worth of benefits rather than utility cost of capital to better capture public good and long life attributes of transmission projects.
- Transmission technologies have an important impact on ratings, power flows, reliability and, hence, the size and flow of benefits among network users. Choice of transmission technologies alone does not resolve benefit quantification and cost allocation issues that were the focus of this research project.

A review and evaluation of current benefit quantification methods utilized in the industry was performed. By and large, current methods are production cost simulation model based and do not adequately capture the full range of strategic and other benefits of major regional transmission projects.

A summary of **key conclusions and recommendations for transmission project benefit quantification** based on this research project are outlined below.

1. **Assessment of Model Based Traditional Benefit Quantification Methods Commonly Used in the Industry**
    - Production cost simulation and present worth analysis methods are commonly used to quantify benefits of transmission projects.
    - Models understate benefits of long life assets (50+years) by discounting future benefits using high interest rate based on cost of capital—essentially reducing the impact of benefits beyond the first 10-years.
    - Models utilize an expected value approach that tends to minimize the consequences of high impact but low probability events.

- Models are data intensive—requiring assumptions about future generation mix, fuel prices, and transmission network.
- Models are static with no feedback—they assume no change in investment for new generation resulting in a zero sum benefit distribution game, for example, Devers-Palo Verde No. 2.
- Extreme market volatility and multiple contingency system events which can be very costly and risky to society are not captured in current models.
    - 2001 California market dysfunction—$20–40 billion.
    - 2003 Northeast Blackout—$5–10 billion.

2. **CA ISO TEAM Methodology is Comprehensive and Incorporates Many Enhancements to Traditional Production Simulation Analysis**
    - CA ISO developed the Transmission Economic Assessment Methodology (TEAM) for benefit analysis of major transmission projects.
    - In the TEAM approach, benefits are measured separately for consumers, producers, and transmission owners in different regions.
    - TEAM incorporates bid-cost markup in the analysis to reflect functioning of markets
    - Uncertainties are considered through a wide range of future system conditions—dry and wet hydro, demand scenarios, gas price scenarios, generation addition scenarios.
    - Expected range of benefits is computed. Insurance and strategic value of transmission is discussed.
    - CA ISO TEAM methodology is recognized as progressive and path breaking.
3. **Research identified several areas that are amenable to advancement in existing benefit quantification methods as well as quantification of strategic benefits including:**
    - Use a social rate of discount to present worth benefits rather than utility cost of capital.
    - Quantifying fuel diversity benefit by taking into account the price elasticity of natural gas.
    - Application of Delphi or other stakeholder consensus generation methods to quantify benefits of mitigating low probability high societal impact events such as major blackouts and market dysfunctions.
    - Application of dynamic analysis.
    - Application of portfolio analysis methods commonly used in the financial services industry.
    - Developing model based techniques to quantify extreme event benefits.

4. **With acceptance by regulators and policy makers, CAISO TEAM Method and other methods in use could be augmented to recognize additional strategic benefits in the following three areas**

    - **Public Good**

      Use a social rate of discount to calculate the present value of benefits for the new transmission project.

    - **Fuel Diversity**

      Include the benefit from a potential decrease of natural gas price due to the construction of a new transmission project that integrates a significant amount of new renewable resources which also reduces natural gas consumption and emissions.

    - **Low Probability / High Impact Events**

      Add risk mitigation benefit to society for low probability/high impact extreme market events and extreme system multiple contingency events—scenarios or Delphi method for stakeholder consensus.

5. **Supporting Additional Research on Benefit Quantification Methods in the Following Areas:**

    - Dynamic Analysis to recognize the impact of new transmission projects on construction of new generation capacity in exporting regions.
    - Portfolio Analysis to assess performance of different combination of demand response, renewables and fuel based generation, transmission and energy conservation programs. Portfolio analysis methods are utilized in the financial industry but research is needed to adapt these techniques to transmission expansion planning.
    - Quantification of Extreme Event Benefits (Insurance Value) in terms of reliability and reduced market volatility. Quantification methods to be researched include application of Value at Risk, Option Value, and insurance premium concept. Reliability benefits can be measured in terms of reducing blackout footprint due to extreme (N-n) events and societal value of reduced risk and exposure to run away market prices.

1.0 Introduction

California's more than 31,000 miles of electric transmission lines and 18,170 MW of interconnection to neighboring states have been critical for efficiently meeting electricity needs of California consumers with high degree of reliability.

There is general policy consensus that new transmission projects are needed to advance the policy objectives of renewables integration, reliability management, efficient market operations, interconnect new load and generators, reduce transmission congestion and bottlenecks, and expand access to regional power markets. Historically, major transmission projects were sponsored and owned by utilities and generally proposed as part of new power plant development by integrated utilities.

This landscape has changed with the separation of generation and transmission assets and separation of transmission operations from ownership by shifting the responsibility of transmission operations from utilities to Independent System Operators/Regional Transmission Operators (ISOs/RTOs) such as CA ISO. These changes in industry structure, operations, and planning impact how new transmission projects are planned, evaluated, and approved. Approval of proposed major regional transmission projects in this new environment has proved to be challenging, witness the difficulty in moving forward with several California based projects such as the Palo-Verde Devers No. 2 line, Sunrise, Rainbow -Valley, and others. This difficulty has brought into focus the need for research on benefit quantification and cost allocation methods to help with the approval of major regional transmission projects.

Utility efforts to develop new transmission projects that are local in nature, address well documented reliability needs, required for interconnecting new load or generation are generally supported and have been gaining regulatory approvals and stakeholder support. However, major regional transmission projects that involve multiple jurisdictions and utilities and are needed for integrating remote resources, reducing costs, improving market operations, providing long term strategic benefits and improving operating flexibility, don't have a clear path forward. Projects cannot go forward without cost recovery certainty. Cost recovery certainty requires allocation of costs through tariffs or contracts. For a major regional transmission project involving multiple jurisdictions and utilities to go forward, there needs to be a consensus on benefits, costs, and allocation of benefits and costs that can be embraced by stakeholders and policymakers.

For example, due to lack of local consensus on benefits or cost allocation. San Diego Gas and Electric's Rainbow-Valley line was rejected by California Public Utility Commission (CPUC). Also, Southern California Edison's (SCE) initial Tehachapi transmission trunk-line proposal for integration of wind resources and the proposed rate and cost recovery treatment was rejected by the Federal Energy Resources Commission (FERC) notwithstanding the extensive stakeholder review process and support from the CPUC, California Energy Commission (Energy Commission) and CA ISO , although FERC did ultimately approve a hybrid approach proposed by the CA ISO to address the ratemaking treatment of the trunk-line costs. Most recently, SCE's proposed Devers-Palo Verde No. 2 to import additional energy into California was rejected by Arizona's Public Service Commission in part because the project did not demonstrate benefits for Arizona.

The Tehachapi Transmission Project to integrate 4,500 MW of renewable wind energy has since been approved after changes were made to the original filing. The estimated project cost is $1.8 billion. The key features of this project include:

- Policy support – needed for Renewable Portfolio Standard (RPS).
- Stakeholder support – renewables development and integration.
- Single utility footprint – Southern California Edison.
- Single jurisdiction for cost recovery – CA ISO, FERC tariffs.
- Cost recovery backstop – CPUC.
- Cost allocation – network facilities rolled in CA ISO rates.

However, other transmission projects that have been proposed for California's rapidly growing transmission needs are facing difficulty in obtaining regulatory approvals due to challenges to the type and quantity of benefits, cost recovery, and cost allocation. These projects include:

- San Diego 500 kV Sunrise Powerlink.
- Imperial Valley Transmission (Green Path).
- Devers-Palo Verde No. 2 500 kV Transmission.
- Path 26 Expansion.
- Trans-Bay Cable Project.
- Lake Elsinore Pumped Storage and associated transmission upgrades.
- Transmission Project from Wyoming to California and other states.

Over the next 10- to 30-year time horizon, additional transmission projects are going to integrate renewables and to expand California transmission and interconnection to various regions which may include for example, Baja-Mexico, Nevada, Arizona, Utah-Wyoming, Pacific Northwest and Western Canada. Additional new in-state and intra-state transmission projects for reliability, deliverability and renewable resource integration are also likely to be needed, for example, Pacific Gas & Electric proposed project to expand interconnections from Northern California to British Columbia through Oregon and Washington.

Major regional transmission projects share some of the following characteristics:

- Multiple regulatory jurisdictions.
- Regional nature.
- Multiple utilities and control areas.
- Involvement by private and public utilities, as well as ISOs/RTOs.
- Non-traditional ownership and development (e.g., Transbay Cable and Lake Elsinore).

- Multiple benefit streams and beneficiaries with varying timing.

The challenge associated with benefit quantification, cost allocation, and approval of new transmission projects was recognized in a September 2007 report prepared by The Blue Ribbon Panel on Cost Allocation[1].

> While the wholesale electricity market has changed fundamentally, the framework for enabling and encouraging investment that will better enable the grid to serve growing competitive markets has not yet fully emerged. One area still largely unresolved is how the costs incurred in transmission expansion will be allocated among users. While it is clear that many traditional cost-allocation approaches are no longer appropriate, new principles governing the allocation of cost responsibility for new transmission investment have yet to be fully articulated and implemented.

Traditional approaches for benefit quantification, cost allocation and rate recovery may not be adequate for justification and development of these transmission projects. This research project focuses on investigating new approaches for quantification of benefit streams over time that may better inform project participants, stakeholders, and policymakers on issues related to project benefits, cost allocation and cost recovery of transmission investments.

1. The Blue Ribbon Panel on Cost Allocation, Sept 2007, *A National Perspective On Allocating the Costs of New Transmission Investment: Practice and Principles*, p 1.

2.0 Research Goals and Objectives

For major regional transmission projects to go forward, there needs to be consensus on benefits, costs, and allocation of benefits and costs that can be embraced by the multitude of players impacted. Projects cannot go forward without cost recovery certainty. Cost recovery certainty requires allocation of costs through tariffs or contracts. This requires an assessment of all of the benefits, including strategic benefits, and then linking these benefits to beneficiaries. The assignment of benefits could then be factored into project cost allocation and cost recovery decisions.

To address these research issues, the project established the following research goals and objectives:

- Review methodologies currently being used for transmission project benefit quantification.
- Review and summarize benefit analyses that have been carried out for some recent transmission projects in California.
- Present and summarize research results to improve benefit quantification methods for new transmission projects.
- Outline approaches to apply improved benefit quantification methods to:
  - Evaluate projects cost effectiveness.
  - Allocate projects cost among participants.
  - Develop framework for cost recovery.

To achieve goals stated above, the research team carried out review of benefit streams and benefit quantification methods that have been used in recent transmission projects. The research has addressed:

- Type of benefits from different transmission projects.
- Current state of assessment methodologies to quantify strategic and non-traditional benefits.
- Assessment of benefit types received by different beneficiaries of a transmission project.
- Types of benefits not adequately captured by current methods.
- Research approaches to improve benefit quantification.

With regard to cost allocation and cost recovery methodologies, the goals and objectives of this study are:

- Review and describe the current methodologies being used for cost allocation and cost recovery of transmission projects.

- Develop a framework for linking cost allocation to different types of transmission projects.
- Summarize alternative models for cost allocation and cost recovery.

The key research result of this project is the development of a framework that could be utilized to guide cost allocation and cost recovery of transmission projects based on the benefits from the projects.

There are many key policy questions that came up as part of this research, for example impact of transmission technologies, impact of industry and regulatory changes, and lessons from other regions and industries. These topics were reviewed and are discussed in the next Section.

The literature and reference list relied upon in this research project are shown in Appendix A. Research project Fact Sheet is provided in Appendix G.

3.0 Review of Other Industries, Regions, Transmission Technologies, Industry and Regulatory Changes

3.1. Review of Other Industries

Electric, gas, and telecommunication industries all rely on networks for transport. During the 1990's, there was a tremendous expansion in telecom transport capacity. Also, gas pipeline capacity has generally kept pace with demand as a result of new pipelines or expansion of capacity of existing pipelines. All three industries rely on physical networks for transport, with the exception that in the telecom industry where wireless technology is utilized for transmission over short distances. While the 3 industries have a lot in common in terms of planning, regulation, and network infrastructure, physical attributes of electric transmission networks result in some important differences.

Electric transmission networks differ in some key respects when compared to other networks such as gas and telecommunications. The most important difference is property rights—electric networks are operated as open access networks with financial rights but not physical property rights. The exception is non-network facilities such as DC lines, radial lines, and point to point links. In addition, the transport capacity of an AC electric transmission line is often determined by network characteristics and can change as a result of parallel network flows and system configuration.

AC transmission lines have other major differences compared to the gas and telecom industries – flows are not controlled (except by use of phase shifting transformers and other flow control devices which can be costly), but determined by the physics of the network; transmission delivery capacity is variable; and the use of transmission is subject to open access rules with transmission owner (or contract right holder) being able to use the transmission on the same terms and conditions for access as other market participants.

Federal Energy Regulatory Commission (FERC) is considering long term transmission contracts, but current open access rules provide no certainty of use of transmission to owners. The owner could achieve financial neutrality through use of financial instruments.

These differences result in transmission networks being viewed more as a "public good" as compared to other networks with property rights.

A summary report on Comparison of Electric Transmission with Gas and Telecommunication Industries is included in Appendix H to this report.

3.2. Lessons Learned From Other Regions

The lessons from other ISOs and regions and research findings related to large regional transmission projects point to some common elements for planning, regulatory, stakeholder involvement and cost allocation and cost recovery processes. For large regional transmission projects, the research findings are that successful transmission projects have the following attributes:

- Strong Project Proponent, generally a utility
- Early Involvement by Regulators and Stakeholders
- Collaboration Among Regulators and Stakeholders Around the Region Impacted by Transmission
- Transparent Planning and Benefit Quantification Process
- Benefit Sharing Among All Affected Participants and Stakeholders
- Predictable Ratemaking Processes for Cost Allocation and Cost Recovery

3.3. Transmission Technologies

The selection of transmission technologies impacts the capacity or ratings, power flows, and grid reliability. Selection of technologies can impact the size of the benefits and distribution of benefits. Some of the key technology options are:

- AC vs. DC technology.
- Type of conductor – conventional, composite, superconductor.
- Application of flow control devices.
- Technology upgrades of existing transmission or construction of new lines.
- Underground vs. Overhead.

These technology choices are determined by economics and physics of the transmission grid. However, the technology decisions are not the major factor in cost allocation, cost recovery or benefit quantification.

A report on transmission technologies is provided in Appendix D to this report.

3.4. Industry and Regulatory Changes.

The electric power industry continues to transition from a vertically integrated cost of service regulated model to a disaggregated mix of regulated and competitive model. These changes are continuing and have impacted transmission planning. The most significant change is that while utilities continue to play a major role in technical aspects of transmission planning ISOs and RTOs have taken over coordination of transmission planning functions within their footprints, including stakeholder participation. Also, the generation development and transmission planning are no longer integrated. To learn from history, the Industry and Regulatory changes are reviewed as part of this research project and are discussed in Appendix E to this report. The key conclusion is that the planning landscape has changed substantially and traditional utility integrated planning methods are not applicable in the current environment, cost recovery certainty is a key element of moving transmission projects forward, and strategic benefits were addressed qualitatively but not quantified.

3.5. Implications for Transmission Projects

The structure of the transmission industry has changed in the last few years. Historically, utilities planned and constructed new transmission lines, obtained regulatory approvals, invested capital, and received a return on the capital by adding the investment to its rate base after the regulatory approval and collecting a regulatory approved revenue requirement for the new transmission added to its rate base. In return, the ratepayers of the utility received all the benefits of this new transmission line such as importing firm capacity and energy, importing or selling economy energy and the transmission revenue from other utilities using this new line. The utility that owned the project was involved in planning, design, permitting, construction, and finally, the operation of the new line.

In the restructured market in California, the CA ISO coordinates the planning with strong participation and input from the utilities on planning and technical issues and involvement by stakeholders. The operational control for grid projects is turned over to the CA ISO. Access to the transmission is open and available to all via FERC approved tariffs. The cost of the new high voltage transmission project is paid through the Transmission Access Charge by all customers using the CA ISO grid. All users have the right to use of the new transmission. The high voltage transmission grid in CA ISO has the characteristic of a "public good," in that 1) owners of the grid cannot reserve the use of the grid for their private benefits and 2) the transmission grid provides social benefits such as reliability, market efficiency, and access to regional markets for all users through payment of the Transmission Access Charges.

3.5.1. Transmission as a Public Good

Two important criteria for a good to be a *public good* are: 1) that consumption by one party does not foreclose consumption by another party; and, 2) that owners of property cannot prevent consumption by others. Good examples are greenhouse gas reduction, air pollution reduction, flood control, and highway systems.

Access to public goods cannot be denied by a private party, though public access may lead to overuse. This can happen with high voltage transmission where the use by one party may create congestion at times, but that is not denial of the usage for others. Everyone will end up paying for congestion or in a word, the benefit decreases for everyone. Of course a party can reduce the negative impact of congestion by financial hedging.

Costs of public good projects are spread over all potential users and beneficiaries. This is the case for highways, dams, flood control, and other public good projects. Under FERC rules, transmission projects costs are spread over all users or socialized.

In addition, large transmission projects produce public benefits, including:

1. Long-term benefits occurring over 50-years and more.
2. Reduce effects of high impact but low probability events.
3. Reduce extreme market volatility and multiple contingency system events that are costly and risky to society.

These types of public benefits are other reasons for benefits of transmission projects to be identified as "public goods."

The Energy Commission consultant report, Economic Evaluation of Transmission Interconnection in a Restructured Market (CEC-700-04-007) prepared by Electric Power Group and the Consortium for Electric Reliability Technology Solutions concluded that high voltage transmission system in California has become a "public good" in the restructured market and recommended that the social discount rate should be used in determining the present worth of the stream of benefits from such transmission projects.

Furthermore, Energy Commission staff in its draft white paper, Upgrading California's Electric Transmission System: Issues and Actions for 2004 and beyond (CEC-100-04-004), based in part on the above EPG/CERTS report, determined that high voltage transmission infrastructure in a restructured world has increasingly become a public good, that project benefits cannot be denied to any retail customers or generation owners, that the utility owner of the project does not control the operation of the project, and finally the capital cost of a new high voltage transmission project is paid by all retail customers in CA ISO grid through the Transmission Access Charge.

With the above view, Commission staff concluded that state decision-makers should apply the "social discount rate" when using the societal test developed by CA ISO to make a decision on the economic value of a transmission project.

Finally, in the 2004 IEPR update, the Commission made recommendation that using a social discount rate, comparable to that used for Commission buildings and appliance standards, for evaluating the costs and benefits of transmission investments is appropriate for the state transmission planning process.

3.5.2. Present Value of Future Benefits—Social Discount Rate

Cost benefit analysis of public good projects have used a social discount rate to calculate present value of future benefits. The revenue requirement of projects is then computed using the project cost and opportunity cost of capital. The social discount rate is lower than cost of capital and captures the societal and public good aspects of benefits of investments which also tend to be long life. The research rationale for the use of social discount rate for new transmission projects is listed below:

- Use of a social rate of discount to estimate present value of benefits of transmission projects will recognize the "public good" nature of transmission projects.
- A social discount rate, generally 3 to 5% is used to evaluate long life public works and public goods projects.
- Public or societal benefits of transmission projects include fuel diversity, common carrier use, integration of renewables, insurance against extreme events, meeting public policy goals.
- Transmission projects are long life—50 plus years. Benefits start to accrue as use of line increases over time. The use of a social rate of discount recognizes the

value of benefits that occur beyond the first ten years of project life in present value analysis, while the use of a higher cost of capital would discount future benefits beyond ten years to a point of being non-significant.

- The present value of benefits using a 4% discount rate is approximately 100% higher than using a 10% cost of capital. With a 10% discount rate, total present value of all benefits beyond ten years in a 50–year project life is discounted to approximately 38% of total present worth of benefits. However, a review of transmission projects confirmed that benefits of transmission projects continue to accrue well beyond the first ten years of operation and generally increase over time.

Application of a social discount rate does not require any change in benefit-cost analysis methodology. However, regulatory and policy support for the concept is critical for its use and application. At a minimum, project proponents should calculate the present value of benefits using both a social discount rate and a traditional cost of capital to provide a sensitivity of calculated benefits to the discount rate.

3.5.3. Application of Social Discount Rate

The question of the *social discount rate* has been discussed among economists and philosophers for many decades. "In the early days of the field, many economists argued that policymakers should be more patient than private citizens. Yet most of their arguments were paternalistic, such as Ramsey's (1928)[2] claim that it was "ethically indefensible" to discount the future."[3] In an essay published in 1950, Maurice Dobb repeated the same argument that, "clearly, for planning purposes we are interested in tomorrow's satisfaction as such, not in today's assessment of tomorrow's satisfaction. To discount later enjoyment in comparison with earlier ones is a practice which is ethically indefensible and arises merely from the weakness in imagination."[4] In the same article, he recommended that the rate of the increase of labor productivity should be used as the basis for fixing the social discount rate.

Social rate of discount has been recommended for economic evaluation of public projects in sectors such as transport, agriculture, water resources development, and land-use. More recently, there have been many reports and articles on the use of Social Discount Rate for evaluation of projects for reducing the impact of global warming. This includes a 700-page report, "The Stern Review: The Economics of Climate Change" in 2006, published by HM Treasury, London. The Stern Review recommended using 0.1 percent for the social discount

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2. A Mathematical Theory of Saving, Frank P. Ramsey, Economic Journal 1928 (December) pages 543-559.

3. The Social Discount Rate, Andrew Caplia and John Leaky, Journal of Political Economy, 2004, Vol 112, No. 6

4. Essay on Economic Growth, Maurice Dobb, Long, 1960 Chapter II

rate and immediately we should invest 1% of the global gross domestic product to reduce the impact of global warming.[5]

Professor William D. Nordhaus of Yale, a noted economist, has a concern with the social discount rate used by Sir Nicholas Stern, and recommends 3% as discount rate.[6]

In a World Bank Policy Research Working Paper, Humberto Lopez estimates the social discount rate for nine Latin American countries based on the recent track record in terms of growth.[7] These social discount rates are in the 3– to 4–percent range for Argentina, Bolivia, Brazil, Chile, Columbia, Honduras, Nicaragua, Mexico, and Peru. The analysis is based on: i) pure time preference rate, ii) the growth rate of per capita income/consumption; and, iii) the elasticity of marginal utility of income/consumption.

Regarding pure time preference rate, there is long-standing debate in literature. On the low side Stern Review uses 0.1%. On the other hand, some have suggested to put an upper bound of 3%.[8]

Lopez, in his analysis for nine Latin America countries, sets the pure time preference rate at 1%. Others have also used numbers around 1%. For example, Kula uses 1.2% for the United Kingdom on the basis of the probability of death in 1975.[9] Scott estimates this rate at about 1.3% based on a century of data on United Kingdom savings behavior.[10] Kula, in his study of the social rate of discount for India, uses a value of 1.3%.[11] Evans and Sezer use range between 1 and 1.5% for six developed countries (Australia, France, Germany, Japan, United Kingdom, and United States).[12]

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5. Recalculating the Costs of Global Climate Change, Hal Varian, New York Times, December 14, 2006

6. OP.cit

7. The Social Discount Rate: Estimates for Nine Latin American Countries. Humberto Lopez, Policy Research Working Paper, The World Bank, Latin America and the Caribbean Region, Office of the Chief Economist, June 2008

8. OP.cit

9. Social Interest Rate for Public Sector Project Appraisal in the UK, USA, and Canada, Kule E, Project Appraisal, 2: 169-174, 1987

10. A Review of Economic Growth, M. Scott, Clarendon Press, Oxford, United Kingdom, 1989

11. Estimation of a Social Rate of Interest for India, Kula E. Journal of Agricultural Economics, 55(1): 91-99, 2004

12. Social Discount Rates for Six Major Countries, Evans, D. and H. Sezer, Applied Economic Letters, 11: 557-560, 2004

There is a good literature review in Humberto Lopez study for the other two elements for estimating Social Discount Rate, i.e., per capita consumption growth rates and the elasticity of marginal utility of consumption.

A standard approach taken in much of the existing empirical literature relies on generating the expectations of the future rate of growth on the basis of past per capita consumption growth rates.

In a study on the elasticity of marginal utility of consumption in a 2004 study[13], Evans and Sezer estimate it at between 1.3% and 1.7% in six developed countries and then Evans in a 2005 paper finds an average of 1.4 % in 20 OECD countries.[14]

The techniques and equations similar to the ones used by Evans and Sezer, and Kula are being used by many economists to estimate the Social Discount Rate for different countries.

David Evans and Haluk Sezer calculate the social discount rate based on[15]:

$$SDR = (1+g)^{|e|}(1/\pi)-1$$

whereas SDR = social discount rate

g = per capita real consumption growth rate

e = elasticity of the marginal utility of consumption

π = weighted probability of survival of the average consumer from one period to the next, which is a measure to capture the pure time preference

Based on this study, the result for United Kingdom for the period 1967-1997 was SDR = 4.87%.

Erhan Kula, using similar formulation, using the data for the period 1954-1976 for the growth rate of consumption and the elasticity of the marginal utility of consumption and for using 1946-1970 data for the annual average survival probability for United States and 1945-1975 data for Canada estimated SDR for United States = 5.3% and SDR for

13. OP.cit

14. The Elasticity of Marginal Utility of Consumption: Estimates for 20 OECD Countries” D. Evans, Fiscal Studies, 26(2):197-224, 2005

15. A Time Preference Measure of the Social Discount Rate for the United Kingdom, David Evans and Haluk Sezer. Applied Economics, 2002, 1026 P.34

Canada = 5.2%.[16]

In a recent article[17], "Discount Rates: The Divine Right of Economists," John Geesman, former Energy Commissioner commented on discount rates. The article noted that: "…discount rate is set to approximate the cost of capital of the real party at interest in the decision, the belief being that such a rate should fully capture the value attached to a choice between today and tomorrow." However, the article continues that, "The construct doesn't work quite as seamlessly with decisions affecting broad swathes of the public, or society at large, so the "cost of capital" is transformed into a "social discount rate". Also, the article noted that the current Bush Administration directed "…its agency heads in 2003 to use both a 7% real cost of capital and a 3% real social discount rate in conducting regulatory evaluations without providing much guidance for when one would be more appropriate than the other" and that "…the California Energy Commission last year directed that utility supply plans be evaluated with a 3% discount rate applied to future fuel costs unless the utilities "can demonstrate that these costs should be assigned to shareholders."

3.5.4. Recommendation For Transmission Projects

In an IEPR Update Committee Workshop held in August 2004, the Los Angeles Department of Water and Power, in its testimony supported the use of social discount rate in calculating the benefits of transmission projects that can be deemed desirable for the "public good." LADWP stated that the State of California already has access to a social discount rate that is well-defined and documented in the long-term bond markets. The state uses these rates in borrowing money for public projects. These rates can and should be used as social discount rate since these funds are prioritized and dedicated for the public good.[18]

Based on the above discussion and observation, the project team recommends that a social discount rate for the United States should be calculated using more recent data on: per capita growth rate of consumption, the elasticity of the marginal utility of consumption, and the probability of survival from one period to the next (an indicator of pure time preference rate), or alternatively the social discount rate should be based on what LADWP recommends.

The research team concludes that a real social discount rate of 3 to 5% would be a reasonable approximation for use in calculating the present value of the stream of benefits from the high voltage transmission projects when benefit streams are calculated in constant dollars. Also a 50–year economic life should be used in calculating the present value of benefits of high voltage transmission lines.

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16. Derivation of Social Time Preference Rates for the United States and Canada, Erham Kula Quarterly Journal of Economics 1984, Vol 99, 11 P. 873-882

17. Discount Rates: The Divine Right of Economists, by John Geesman, former California Energy Commissioner, Green Energy War, August 13, 2008.

18. Los Angeles Department of Water and Power, comments of the Los Angeles Department of Water and Power on topics discussed at the August 23, 2004, Upgrading California's Transmission System: Issues and Actions for 2004 and Beyond Workshop, September 7, 2004.

4.0 Current Methodologies For Benefit Quantification

4.1. Types of Projects

All transmission projects have attributes that relate to reliability, economics, and operations. However, the processes that are used for economic evaluation and cost recovery of projects varies depending on the type of project, and for this purpose, transmission projects are generally grouped into four categories:

- Requested Upgrades.
- Generation Interconnection.
- Reliability (Base Plan Upgrades).
- Economic (Supplemental Upgrades).

Requested Upgrades are projects that meet specific request or requirements of a customer and are usually paid by the customer.

Generation Interconnection is to connect a new power plant to the electrical system and is usually paid by the generator. There may also be need for system upgrade as a new significant generator is being added to the system.

Reliability projects are transmission improvement that may be required to satisfy the existing or new reliability criteria. Without such a transmission, there is potential for reliability related problems and failure to meet the established reliability criteria.

Research indicates that the first three types of projects—requested upgrades, generation interconnection, and reliability projects have clear drivers or mandates and tend to go forward with little or no opposition. However, economic projects (including projects that address specific policy objectives such as renewables integration and debottle-necking) often get stymied due to different perspectives on need, benefits, and cost responsibility.

The economic projects are proposed to reduce the total cost to society. This includes economic projects that are used for reducing bottlenecks and congestion, expanding access to regional markets, meeting policy goals such as Renewable Portfolio Standards (RPS), and providing insurance against multiple contingencies.

In this research, the emphasis is on methods that can be used to quantify benefits and allocate costs of Economic (Supplemental Upgrade) transmission projects. The research results are applicable to other types of projects and to projects that exhibit multiple dimensions of economics, reliability, and operations.

4.2. Types of Benefits

The benefits from an economic transmission project can be grouped into:

- Primary Benefits (Traditional Benefits).
- Strategic Benefits.

- Extreme Event Benefits.

There are also secondary benefits from new projects. These include: economic development, tax base increase, use of right-of-way, and impact on infrastructure development. These secondary benefits are not addressed in this study.

Primary or traditional benefits can be defined as cost reduction, congestion reduction and expansion of access to regional markets to take advantage of load and resource diversity. Primary benefits improve network reliability and result in lower cost of energy and capacity adjusted for transmission losses.

Strategic benefits can include:

- Access to new renewables resources to meet Renewable Portfolio Standard (RPS).
- Promote efficient market operation and market power mitigation.
- Promote fuel diversity.
- Provide emission reduction/environment benefits.
- Improve deliverability.
- Insurance against contingencies.
- Meet policy goals such as Renewable Portfolio Standard.

These strategic benefits all contribute to lower cost electricity or risk for consumers, and if properly quantifies, will show larger streams of benefits of transmission projects than what has traditionally been quantified.

There are also secondary benefits from new projects. These include: economic development, tax base increase, use of right-of-way, and impact on infrastructure development. These secondary benefits are not addressed in this study.

The types of benefits of new transmission projects depend on whether the region is at the generation or exporting end or importing end of the transmission line. Benefits accruing to a region are a function of location with respect to a transmission line as follows:

- Exporting Region Benefits
    - Regional economic development.
    - Increase tax base.
    - Reliability Improvement.
    - Expansion of generation resources.
- Importing Region Benefits
    - Import of lower cost energy and capacity.
    - Reliability improvement.
    - Strategic benefits:

    - Access to renewables.
    - Fuel diversity.
    - Emission reduction.
    - Insurance against contingencies.
    - Increased deliverability.
    - Decrease *Market Power*.
- Exporting and Importing Region Benefits
    - Seasonal exchange.
    - Sales of surplus energy.
    - Reserve sharing.
    - Reliability improvement.

There are many uncertainties that impact the size of primary benefit and types of strategic benefits from a new project. These uncertainties include load forecast, fuel prices, development of new generation and retirement of existing power plants, regional prices for electricity, and environmental regulation. Production cost-simulation, scenario analysis, stochastic modeling, and other techniques have traditionally been utilized to estimate a base level of benefit and the sensitivity analysis to take into consideration future uncertainties. These models tend to come up with base case, sensitivity cases, and expected value of benefits.

Another category of benefits relates to extreme events. In recent years, the August 2003 Northeast Blackout and the California 2000–01 market dysfunction put a spotlight on the significant economic (billions of dollars) and societal impact of such extreme events. The challenge is that traditionally, there has been no attempt to quantify the benefit of mitigating extreme events or when it is done, an expected value approach is utilized which understates the societal value of mitigating these very low probability but very high impact events.

One of the research conclusions is that insurance against extreme events should be defined as an additional societal benefit for reducing exposure to extreme market volatility and multi-region-wide blackouts due to multiple contingencies. While there is general consensus on the existence of these types of strategic benefits, they are not easily quantified or captured using traditional models. For example, policymakers anecdotally acknowledge the value of transmission projects as insurance against contingencies, but there is no definition or examples of quantification of such values.

The above category of benefits can be defined as Extreme Event Benefits and are in addition to the Primary and Strategic Benefits. The value of extreme event benefits can be put in context when some of recent power system experiences are examined. For example:

- 2001 California market dysfunction and volatility with a cost of $20-40 billion.
- 2003 Northeast Blackout due to multiple contingencies with a cost of $5-10 billion.

Extreme Event Benefits can be defined as:

1. Reliability—which is based on improved network load carrying capacity and ability to reduce or mitigate impact of extreme events resulting from multiple contingencies (N-3, 4, 5, 6 events).
2. Market Volatility—which is based on the societal benefit of reduced vulnerability to extreme price volatility which could result from extreme system events, market dysfunction, or a combination of factors.

Society's willingness to buy protection against extreme events is well established in the insurance industry, for example hurricane insurance, life insurance, re-insurance against major losses. In each of these examples, there is a well established actuarial data base that allows valuation of such insurance. However, there is not a rich data base related to extreme events in the electric power industry because major blackouts and market dysfunctions are infrequent events. Hence, the research challenge is to come up with alternative approaches that address these benefits rather than dismiss them due to difficulty in quantifying them.

4.3. Benefits Assessment Approaches in Use

The transmission project benefit quantification approaches in use include:

- Production Simulation Models.
- Decision Analysis Models.
- Screening Analysis Models.
- Tipping Point Analysis.

These approaches are discussed briefly in this section and in Appendix B.

For economic benefit quantification of new transmission projects, the basic approach is to utilize a Production Simulation Model. The analysis includes two alternatives: one with and another without the proposed new transmission project. Many commercial production simulation models are available, such as PROSYM, GEMAPS, PROMOD, and PLEXOS. Using a least cost dispatch principle, the models forecast production from different generation resources and associated fuel consumption, and emissions. To have a balance between loads and resources, additional generation resources are also introduced over time. Based on fuel prices, costs of various emissions and variable O&M costs, the total production cost over time are calculated for a given load forecast and associated load shape. The difference in the total production costs from the two simulations defines the gross benefit for the new transmission project.

The net benefit of the transmission project is then calculated by subtracting the capital cost and annual O&M of the transmission project from the estimated gross benefit. Benefit cost ratios and internal rate of return can also be calculated from the information provided by the annual production costs, capital, and O&M expenditure of the transmission project.

To take into consideration the uncertainty of factors such as fuel costs, load forecast, and capital cost of the transmission project, Decision Analysis Models have been utilized to estimate the expected value and the distribution of net benefit or benefit cost ratio. These may also utilize

Influence Diagrams that show the factors that have great impact on benefits and costs of the project.

Carrying out detailed production cost simulation with and without the proposed project are data intensive, time consuming, and expensive. This becomes more difficult when the detail of transmission network is included in the model in addition to the generation system. Furthermore, information on planned new generation development is based on market economics and data is generally not available beyond 5 to 10 years, while transmission projects are expected to last 50-years or more and deliver benefits during the entire period.

At the pre-feasibility level the use of a Spreadsheet Screening Analysis may facilitate studying many transmission options quickly and at less time and expenditure than using detail production simulation models. An example of this approach will be discussed later when the benefit-cost analysis of Frontier Line is reviewed.

Spreadsheet Screening Analysis is useful when new generation resources at export region plus a new transmission is compared with new generation resources at import region. This approach allows comparison of many alternatives quickly. The results provide forecast of fuel consumption, emission, and variable O&M and fixed O&M costs. Benefit and cost of a new transmission is then calculated based on such information for different alternatives by including capital costs of generation at export and import regions, fuel prices and capital cost of the transmission project.

To concentrate the analysis on assumptions and relationships that greatly influence the project benefits, the use of a Tipping Point Analysis method is sometimes utilized. In applying this method, an economic criterion for the project is established. Potential tipping points which are associated with key variables are listed and tested. The level of tipping point where benefit/cost is less than one are determined and the potential for ending up with benefit/cost less than one are evaluated and discussed for these tipping points.

4.4. Review Of Benefit Analysis Of Some Recent Projects

CA ISO's existing and proposed transmission planning process and case histories of recent projects are in Appendix F.

In this section, the analytical tools and benefits quantification methods for benefit analysis for three different projects are discussed. The three projects are Devers-Palo Verde No. 2 (DPV No. 2), Tehachapi, and Frontier Line.

4.4.1. Devers-Palo Verde No. 2

Economic evaluation of Devers-Palo Verde No. 2 has been carried out and reviewed by many parties, including CA ISO, SCE, Division of Ratepayer Advocates (CPUC), and Consortium for Electric Reliability Technology Solutions/Electric Power Group (CERTS/EPG) for Energy Commission.

SCE's objectives for proposed construction of DPV No. 2 are to:

- o Increase California's access to low-cost energy from the Southwest.

- Enhance competition among generating companies supplying energy to California.
- Provide additional transmission infrastructure to support the development of additional generation capacity that will sell energy into California market.
- Provide increased reliability and flexibility in operating California's transmission system.

SCE has used a production cost simulation model (PROSYM) to estimate energy cost saving resulting from the construction of DPV No. 2. This project is estimated to decrease electricity prices in California, which is the primary benefit of this project. There will also be additional third party transmission revenue due to increased CA ISO wheeling through or out of the CA ISO grid.

Southern California Edison evaluation shows a B/C ratio for DPV No. 2 at 1.7. Energy benefits are based on production cost simulation for 2009–2015 and then escalated at GDP price index (around 2.28% per year) for the rest of economic life of the project.

At the request of CA ISO, SCE has provided energy production cost for Western Electricity Coordinating Council (WECC) for the years 2009 through 2014 with and without DPV No. 2. Using the cost saving numbers provided by SCE for WECC, the present value of the quantified benefits from energy and third party transmission revenue is less than the capital cost of DPV No. 2, using a 5% discount rate.

The WECC regional benefit for this project is low, in part, because strategic benefits such as insurance value during extreme system conditions, reduction in generators market power, potential for development of new generation outside of California and environmental benefits beside NO_x reductions are not quantified in WECC regional benefit calculation.

CA ISO has used its Transmission Economic Assessment Methodology (TEAM) approach and PLEXOS cost production simulation model to quantify the benefits from DPV No. 2. Benefits include cost saving in energy, transmission loss reduction, emissions reduction, market power mitigation, and contingency. CA ISO's proposed methodology for benefit quantification of the transmission projects address the following major issues: modeling of market power; development of a robust set of scenarios; selection of appropriate simulation tools or programs; a detail representation of the transmission network and the assumptions of the future generation system; and, selection of benefit tests. Detailed description of these elements is provided in a report prepared by Consortium for Electric Reliability Technology Solutions/Electric Power Group for the Energy Commission in June 2004[19].

Benefit tests examined by the CA ISO includes:

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19. Consortium for Electric Reliability Technology Solutions/Electric Power Group, June 2004. Economic Evaluation of Transmission Interconnection in a Restructured Market, California Energy Commission (CEC-700-04-007), pages 10-12.

- The participant/ratepayer test (benefits to those entities that will be paying for the new facility).
- The societal test (benefits to all consumers, producers, and transmission owners, regardless of who pays for the upgrades).
- The modified societal test recognizing or excluding non-competitive revenues (monopoly rent) collected by some producers.

The societal test is measured by the change in production costs across the entire interconnection (in case of DPV No. 2 over the entire WECC). A transmission expansion project is deemed to pass the benefit test if: 1) it benefits each participant, and 2) the entire societal or the modified societal benefit exceeds the project cost.

The WECC base case data is the foundation of the CA ISO modeling. CA ISO's PLEXOS model of the entire WECC requires significant amounts of input data. Due to the limited available CA ISO staff time for the collection of input data for each year, CA ISO modeling for the economic analysis of DPV No. 2 was done only for two years—2008 and 2013.

CA ISO in its quantification of DPV No. 2 benefits included:

- Operational benefit—such as saving from generation unit commitment costs, minimum load compensation and redispatch of units to address real-time transmission congestion.
- Capacity benefit—such as utilization of some of the surplus capacity in Arizona.
- Loss savings – reduction in transmission losses as a result of DPV No. 2 operation, which were not captured in the DC Power Flow Model.
- Emission reduction—the emission were not directly modeled in the production simulation model.

In the CA ISO evaluation, the above benefits were significant portion of the total benefits[20].

CA ISO's goals in the development of Transmission Economic Assessment Methodology (TEAM) have been[21]:

- Development of a common methodology to evaluate economic need for transmission upgrades.
- Presenting a framework that will be useful in making effective decision on transmission investment.
- Providing transparency in methods, databases, and models so a variety of stakeholders can understand the implications of a transmission upgrade.

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20. CA ISO Department of Market Analysis and Grid Planning, February 2005, Economic Evaluation of the Devers-Palo Verde No. 2.

21. Transmission Economic Assessment Methodology (TEAM), Anjali Sheffrin, June 14, 2004. California Energy Commission IEPR Workshop on 2004 Transmission Update.

CA ISO filed TEAM with CPUC in June 2004. CA ISO has demonstrated in actual studies the use of TEAM for Path 26 and DPV No. 2. The methodology clearly indicates impacts of a new upgrade at the participants' level and also regional (WECC) levels.

Several new elements identified in this research could be added to TEAM to further expand quantification of benefits, such as:

- o Extreme event benefits such as improve network load carrying capacity under multiple contingencies.
- o Reduced vulnerability to extreme price volatility due to long term outages and catastrophic events.
- o Dynamic impact of a large transmission projects on the development and construction of additional generation capacity in the exporting region.

By adding the above benefits to TEAM, the methodology will be able to capture the benefits from risk mitigation of low probability/high impact extreme market events and the benefits of development of new generation to both exporting and importing region. Without taking into consideration such dynamic impacts, the analysis becomes a zero-sum game whereby there are higher electricity prices in the exporting region with the implication that the investment in a transmission line has negative impact on consumers of the exporting region. In fact, this factor contributed to the recent rejection of DPV No. 2 by the Arizona Corporation Commission.

Division of Ratepayer Advocates at CPUC has also carried out a review of the DPV No. 2. This report was prepared in three volumes that were published in November 2005. Volume 3 of this study describes the Tipping Point Analysis for DPV No. 2[22].

As described by Dr. House in his DRA Testimony, *Tipping Point* analysis has gained popularity in the social sciences since Gladwell's 2000 book, *How Little Things Can Make a Big Difference*[23]. The analysis starts with defining the topology of the interactions (similar to the Influence Diagram in Decision Analysis). Then through some analysis it is determined which interactions are critical to the outcome (tipping points).

Dr. House's analysis shows that tipping point variables for the DPV No. 2 project are:

- o Natural gas price differential between Arizona and California.
- o Generation resource plan in Arizona.
- o Palo Verde Nuclear Plant outage.
- o Wholesale natural gas prices.

Based on analysis performed, the following conclusions were reached:

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22. Testimony of Lon W. House, November 22, 2005, *Tipping Point Analysis and Attribute Assessment for DPV No. 2*, Office of Ratepayer Advocate's Devers Palo Verde No. 2 Testimony Vol. 3 of 3.

23. Malcolm Gladwell, 2000, *The Tipping Point: How Little Things Can Make a Big Difference*, Little Brown and Company, New York.

> "In order for DPV2 to be cost effective, the natural gas price differential between Arizona and California has to be greater than $0.50/MMBtu, the wholesale Topoc price of natural gas has to be greater than $5.00/MMBtu and Palo Verde (Nuclear Generation Station) has to be operating."[24]

Furthermore, DPV No. 2 is more valuable to California in the event of an outage of San Onofre Nuclear Generation Station (SONGS).

Tipping Point Analysis provides clear information on critical variables and allows the analyst to concentrate on high impact factors rather than spend a great deal of time and effort on elements that do not materially change the outcome of the analysis.

4.4.2. Tehachapi Transmission Project

Tehachapi Transmission Project is designed to access wind generation resources in the Tehachapi area along with associated system upgrades beyond the first point of interconnection. SCE is the project sponsor. The goal is to develop transmission that will be the *least-cost* solution to reliably interconnect 4,350 MW of generating resources in the Tehachapi Area Generation Queue to the CA ISO grid.

In addition, the project also addresses the reliability needs of the CA ISO controlled grid caused by load growth in the Antelope Valley area, as well as transmission constraints South of Lugo.

The main benefit of this project is to enable California utilities to buy power from wind generation projects and to comply with the state mandated Renewable Portfolio Standard (RPS) program.

The project justification for Tehachapi is renewable resource integration and reliability. While resource integration has an economic dimension, the project justification is based on meeting state RPS mandates rather than benefit cost analysis. The Tehachapi project evolved from the Tehachapi Collaborative Study Group, which was formed in 2004 at the direction of CPUC. The goal was to develop a comprehensive phased transmission development plan for integration of renewables planned for development in the Tehachapi area. Two reports were issued and submitted to CPUC in March 2005 and in April 2006. The outcome was the identification of a number of alternatives for the transmission infrastructure. A recommendation was made to further study these alternatives by the CA ISO.

The CA ISO in full collaboration with SCE and stakeholders carried out the Tehachapi Transmission Project study as part of its CA ISO South Regional Transmission Plan for 2006 (CSRTP-2006). A least-cost solution for the interconnection of planned generation was developed by CA ISO.

The total cost of the Tehachapi Transmission Project is estimated at $1.8 billion in nominal dollars. This cost excludes the cost of Interconnection Facilities (radial wind collector transmission systems that will interconnect the individual generation projects to the grid and

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24. Reference 5, Page 38.

will be the responsibility of generation developers). SCE is the Project Sponsor and the project is subject to necessary regulatory approvals from CPUC and FERC, *which have either been received or expected*.

The Tehachapi Transmission project phased development plan includes:

- Antelope - Pardee, 230 kV line and Antelope Substation Expansion.
- Antelope-Vincent 230 kV Line #1, 500 kV.
- WindHub Substation.
- Antelope-Wind Hub 230 kV line, 500 kV.
- Antelope-Vincent 230 kV Line #2, 500 kV.
- Low Wind 500/230 kV Substation with loop-in of Midway-Vincent #3 500 kV line.
- Antelope-Low Wind 500 kV line.
- WindHub Substation 500 kV Upgrade.

One or more of the transmission line segments may be characterized as bulk-transfer gen-tie for an interim period of time until additional lines and transmission interconnections are built. For these lines, characterized as bulk transfer gen-tie lines, generators would be charged a pro-rata rate for transmission service over the gen-tie line. The residual revenue requirement for any unsubscribed portion of the gen-tie line would be recovered either from retail ratepayers under CPUC-approved rate or from all transmission customers in FERC-jurisdictional Transmission Access Charges (TAC) rates. If any of these bulk-transfer gen-tie lines are later converted into a network facility, then generators would be relieved of their pro-rata share of the transmission service charge respectively.[25]

CA ISO has used the concept of *clustering* in the Tehachapi Transmission Project. *Clustering* allows the study of the system impacts of a group of interconnection requests collectively, rather than evaluating each potential generation project one at a time. This results in greater efficiency in the design of needed network upgrades.

The clustering approach for the Tehachapi Transmission Project will result in substantial capital cost saving compared to any piecemeal upgrade solution with a traditional project by project approach.

However, in the Tehachapi Transmission Project, the CA ISO has deviated from a typical clustered interconnection study. The CA ISO study considered only the network components or network upgrades of the transmission system and excluded the radial wind collector transmission systems. Furthermore, an element of clustering is the selection of a time window for determining which generation projects in the queue will be included in the cluster (i.e., the *Queue Cluster Window*). The Tehachapi Transmission Project defined the Queue Cluster

25. Armie Perez, Vice President of Planning and Infrastructure Development, January 18, 2007, Memorandum to CA ISO Board of Governors, Page 6.

Window as the projects submitted from August 19, 2003 through April 2006, which exceeds FERC limit of 180 days for the Queue Cluster Window.

Due to the specific circumstances presented by Tehachapi Project, CA ISO has filed a petition with FERC for approval to proceed with the proposed study approach on a one-time basis.

CA ISO Board has approved the Tehachapi Transmission Project as the Network Upgrades necessary to allow Generating Facilities in the Tehachapi Wind Resources Area to deliver their output to CA ISO grid. The Board has directed SCE to proceed with the permitting and construction of this project. FERC's approval of the CAISO waiver request for provisions of Large Generator Interconnection Procedures (LGIP) allowed this project to move forward.

4.4.3. Frontier Line

The Western Regional Transmission Expansion Partnership (WRTEP) is proposing the construction of Frontier Line, a large transmission project between Wyoming, Utah, Nevada, and California.

To perform a screening level economic study, the Economic Analysis Subcommittee developed a spreadsheet tool to quantify benefits and costs of multitude of possible alternatives and scenarios. These alternatives included: a variety of load and resources scenarios, a myriad of conceptual transmission links and configurations identified by the Transmission Subcommittee; a wide range of natural gas prices and possible costs for new clean coal technology, including integrated gasification combined cycle (IGCC) and carbon dioxide sequestration; and a broad spectrum of potential policy actions such as regional and/or national renewable portfolio standards, state and federal tax incentives for preferred resources such as wind or solar or clean coal, and regulatory regimes in greenhouse gas emissions.

To carryout these benefit-cost analysis in a transparent manner, the Economic Analysis Subcommittee designed and constructed a unique analytical tool, the Frontier Economic Analysis Screening Tool (FEAST). The intent was to develop an analytical tool to enable the Economic Analysis Subcommittee to carryout analysis at a screening level which will provide an understanding of the ranges of assumptions under which the development of the Frontier Line will be cost effective and for which more detailed economic analysis using a detailed system production cost simulation will be warranted.

FEAST is a simple tool for knowledgeable users. It considers incremental resource additions, not a complete supply stack which would include all the existing generators.

For this screening analysis, the Gross Benefits ($) of the transmission project is based on the following formula:

Gross Benefit =	Energy Potential	x Line Utilization	x Regional Basis
	MWh	(%)	$/MWh

Energy Potential is the rated capacity of the line multiplied by 8,760 hours. For example, if the Frontier Line is rated 3,000 MW, then energy potential would be 3,000x8760 or <u>26,280</u> GWh per year.

Line Utilization is a function of the quantity and characteristics of resources available to be imported as compared to the line's energy potential. (Basically, capacity of generation resources installed in exporting region multiplied by assumed capacity factors for each resource and subject to the transmission line and system constraints.)

Regional Basis is the energy cost difference between the exporting region and the importing region. This Regional Basis is influenced by many factors, including the capital cost of new generation resources, fuel costs (gas, coal, and others), environmental mitigation costs, renewable energy price premiums, Green House Gas (GHG) adders, and others.

Benefits in addition to energy benefits include: capacity, losses, emissions, insurance value against extreme events, economic impacts due to construction of transmission and generation facilities, tax benefits, reliability improvement and others.

Many of the subcommittee members provided input on fuel prices, capital cost for generation, ranges for Green House Gas adder, capacity factor for wind energy in different regions, and other assumptions. The FEAST Spreadsheet Model was developed by staff of PG&E.

FEAST can handle several exporting regions (source options): Wyoming and Montana (coal and wind), and several importing regions (sink options), including Utah, Nevada, Arizona, and California. Resources considered for importing regions can be gas-fired CT or CCGT or IGCC and renewables (for Utah coal, gas, renewables). For exporting regions, resources can be wind and/or clean coal.

A mix of generation resources for exporting and importing regions are assumed. Taking into consideration capacity and capacity factor of these generation resources, the amount of energy going from source to sink is calculated.

FEAST is an energy focused analysis. Attempt is made to balance energy produced from the generation resources in the sinks and sources. The installed capacity of generation ends up being different for sinks and sources.

The Economic Analysis Subcommittee performed its work using a participatory stakeholder process. Volunteers led the effort to create FEAST inputs. Individual subcommittee members were able to perform their own analysis based on some of their own inputs.

The final report of this subcommittee was submitted to Western Regional Transmission Expansion Partnership (WRTEP) on April 27, 2007[26]. Two most important conclusions of the report were:

1. The benefits of the Frontier Line appear greater than the costs under a variety of plausible scenarios.
2. Uncertainty associated with key inputs results in a wide range of benefit-cost outcomes.

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26. Economic Analysis Subcommittee for Western Regional Transmission Expansion Partnership, Final Report April 27, 2007, *Benefit-Cost Analysis of Frontier Line Possibilities*.

The economics of the Frontier Line, as expected, are very sensitive to natural gas prices and the values used for GHG adder. Economics of the Line are also somewhat sensitive to capital costs for clean coal technologies, including IGCC and CO_2 sequestration.

The primary focus of the analysis that was carried out by the Economic Analysis Subcommittee was economic efficiency from a total societal point of view, i.e., the analysis produced the overall benefit-cost ratio for the region as a whole. Of course, it is important that the Frontier Line produces benefit for each individual jurisdiction participating in the project, i.e., benefit be greater than cost for each state. The Economic Analysis Subcommittee did not analyze cost allocation so that each jurisdiction participating receives a net benefit from the project. However, FEAST enables each user to perform its own analysis and assess benefits and costs allocated.

As stated in the Final Report of the Benefit-Cost Analysis of Frontier Line, FEAST is not a substitute for production costing simulation tools. Analysis using FEAST may be a first step to quickly sort through a multitude of possibilities. FEAST is a tool to perform quick what-if screening analysis. It is a simple spreadsheet-based tool enabling and empowering sophisticated users to carryout a variety of analyses quickly, with the aim of developing user insight rather than producing overly precise numerical results[27].

4.5. Benefit Analysis Observations And Conclusions

The three projects reviewed for benefit analysis are representative of a wide range of potential future large regional transmission projects. A summary of the projects analyzed is presented in Figure 1.

27. Reference 9 p 8.

Summary of Benefit Analysis of Transmission Projects

Project	Description	Purpose	Comments
Palo-Verde Devers No. 2	▪ 500 kV line between Arizona and California ▪ Single utility and single rate jurisdiction (CA ISO) ▪ $500 million cost ▪ 1,300 MW capacity	Reduce California electricity costs	▪ Benefits to California estimated using production cost and sensitivity analysis ▪ Strategic and regional benefits not addressed ▪ Static analysis – assumed generation capacity fixed
Tehachapi	▪ Designed in several phases to interconnect 4,350 MW of new wind generation ▪ Required CA rate back-stop and innovative CA ISO tariff to allocate costs ▪ $1.8 billion cost ▪ Costs allocation among generator (gen-tie), CA ISO grid users, and CA ratepayers for cost recovery back-stop	Enable integration of new wind generation in CA ISO queue to meet RPS	Least cost solution to meet RPS mandate.
Frontier Line	▪ 500 kV ▪ 3,000 MW ▪ $2 billion cost ▪ Multi-state, multi-utility, multi-jurisdiction	Designed to enable construction of new generation in Wyoming/Montana for export to CA, NV, UT, AZ	▪ Benefits estimated using screening model – FEAST ▪ Benefits result from cost differential (capital and fuel) between resources developed in CA vs. WY/MT ▪ Strategic benefits not quantified ▪ Strong state government support in exporting regions ▪ No strong utility project sponsor

Figure 1. Summary of Benefit Analysis of Transmission Projects

Of the three projects, Tehachapi is moving forward. Palo Verde-Devers No. 2 was rejected by the Arizona Commission and SCE, the project sponsor, is moving ahead to construct the California segment of the transmission line and continuing to pursue approval from FERC for the Arizona portion. Frontier Line is still in the conceptual planning stages.

From this review, the following observations and conclusions are presented.

1. Elements of successful projects, e.g., Tehachapi
    - Strong project sponsorship.
    - Extensive stakeholder participation.
    - Clear objectives and benefits, whether quantifiable or not.
    - Cost recovery certainty.
    - Policy and regulatory receptivity.
2. Benefit quantification
    - Primary methods used are production simulation or screen methods.
    - Benefits are based on cost differentials for different options, i.e., project vs. no project or comparison of different project options.
    - Many strategic benefits were not quantified.

- Analysis required data intensive assumptions about future loads, resources, fuel prices, and policies.

3. Problems encountered by projects
    - Limited showing of benefits for key stakeholders, e.g., Palo Verde-Devers No. 2.
    - Ambiguity about objectives and goals, including changing policies, e.g., Frontier Line.

5.0 Benefit Quantification Methods

5.1. Assessment of Current Methods

Primary method to quantify the benefits of a transmission project is the use of a production cost simulation model such as PROSYM, GEMAPS, PROMOD, and PLEXOS. The difference in the total production cost for with and without the transmission project provides information on gross benefit from such a project.

Key input variables in the production cost simulation models that impact the benefit of a new transmission project are:

- Fuel prices at different regions.
- Generation development—type, location, and timing.
- Retirement of the existing generation resources.
- Operation cost and performance of existing and new generation.
- Emission rates and values.

The key conclusion of research review of recently approved or proposed transmission projects to assess benefit quantification methods is that benefit quantification methods rely primarily on production cost savings and do not quantify reliability and strategic benefits. Specifically, current methods don't capture the benefits of reducing vulnerability to extreme events or dynamic impacts resulting from the interaction of the new transmission projects with base case assumptions that are used to evaluate benefits, for example, the feedback impact on gas prices, fuel diversity, addition of new capacity, and access to new markets.

For example, during California's 2001 electricity crises, the electric markets were dysfunctional. Market prices were persistently high and led to state government intervention on behalf of California consumers. This electricity crises cost the California consumers $20-40 billion. Additional transmission would have mitigated these impacts of market dysfunction but current benefit quantification methods do not take such extreme events into account. Similarly, the August 14, 2003 Northeast[28] blackout, another extreme event, cost between $5– to $10 billion, and the impact would have been substantially less of additional transmission was in place by reducing the footprint and magnitude of this extreme reliability event. This short-coming of current methods was also recognized in a report prepared by the WECC Seams Steering Group[29], which noted that:

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28. U.S.-Canada Power System Outage Task Force, April 2004, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations

29. "*Framework for Expansion of the Western Interconnection Transmission System*", Seams Steering Group – Western Interconnection (SSG-WI), Oct 2003. (Citation 57 from page 30), The Battle Group International Review of Transmission Arrangements, Oct 2007

The real societal benefit from adding transmission capacity come in the form of enhanced reliability, reduced market power, decreases in system capital and variable operating costs and changes in total demand. The benefits associated with reliability, capital costs, market power and demand are not included in this {type of production cost} analysis.

Review of current methods used to quantify transmission project benefits leads to the following conclusions:

- Models understate benefits of long life assets (50+years) by discounting future benefits using high interest rate based on cost of capital—essentially discounting the benefits beyond the first 10-years to a very small percentage of total benefits.
- Models utilize expected value approach that tends to minimize impact of high impact but low probability events.
- Models are data intensive—require assumptions about future generation mix, fuel prices, and transmission network.
- Models are static with no feedback—assume no change in investment for new generation resulting in a zero sum benefit distribution game, for example, Devers-Palo Verde No. 2.
- Extreme market volatility and multiple contingency system events which can be very costly and risky to society are not captured in current models.

The understatement of the benefits of transmission projects using current methods is a serious limitation in evaluation of transmission projects by policy makers. Transmission projects have a long planning lead time (5 to 15-years). Transmission projects are also lumpy, typically 1,000 MW or more and it takes several years to fully realize the benefits. Current methods generally estimate benefits by assuming a generation mix and load pattern during the first year or first few years of project operation and calculate the gross annual benefit as the annual difference in the total production cost with and without transmission project. To carry out benefit-cost analysis, the present worth of the gross annual benefit is calculated using an interest rate. For investor-owned utilities this interest rate is based on allowed weighted cost of capital, generally 10% or higher.

However, use of cost of capital as the basis for discounting the future benefits tends to understate the benefits of long life assets such as transmission. An alternative approach is to use the social rate of discount instead of using a rate based on cost of capital. The social rate of discount (around 5%) can be used to calculate the present value of benefits for the new transmission projects since transmission system has become a *public good* with assets having long life, and benefits occurring over a long period.[30]

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30. Consortium for Electric Reliability Technology Solutions/Electric Power Group, June 2004, *Economic Evaluation of Transmission Interconnection in a Restructured Market*, California Energy Commission CEC-700-04-007.

The impact of using the social rate of discount around 5% compared to the current weighted cost of capital of 10% on present value of benefits is significant. For a project with uniform benefit over 50-years of economic life, the use of 5% discount rate rather than 10% will increase the present value of benefits by around 60% or more.

All of the production cost simulation models capture primary benefits from transmission projects. They include energy, capacity, transmission loss reduction, and environmental values (emissions). Strategic benefits such as access to new renewable resources, fuel diversity, improved deliverability - reduced congestion and insurance against contingencies such as dry hydro condition and performance of some major base load generation and intertie transmission can also be quantified through scenario and sensitivity analysis or stochastic modeling.

Quantification of some of the strategic benefits, such as mitigation of market power is more difficult, but procedures have been developed recently to capture these types of benefits. Effort by CA ISO and the development of TEAM approach for benefit quantification of transmission projects is a good example of the recent efforts.

In summary, current analytical models capture most of the primary and strategic benefits of the new transmission projects. These models utilize the expected value approach and, therefore, tend to *average* extreme low probability/high impact events. However, extreme market volatility and system events can be very costly to society and the societal risk preference and tolerance is not captured in current models. Furthermore, cost of such events multiplied by their probability will under-estimate the financial and social significance of these events and their long term financial dislocation. Extreme market volatility can be very costly to society, such as 2001 California market dysfunction with $20 to $40 billion cost. The value of transmission in mitigating societal impact from these types of events is not captured in current production cost simulation models.

Reliability benefits of new transmission in strengthening the grid and reducing the likelihood of the impact of extreme multiple contingency events is also not considered or quantified in benefit-cost analysis. A good example is the 2003 Northeast Blackout with $5 to $10 billion cost.

Another type of benefit that is not captured in the dynamic impacts of a large transmission project is the natural gas price reduction when the transmission project provides access to significant amount of renewable resources, or production from clean coal generation plants with CO_2 sequestration. Such projects may reduce the demand on natural gas significantly and therefore reduce the price for this fuel. Another dynamic impact is the development of additional generation capacity in the exporting region when a new transmission project is constructed.

5.2. Methods to Improve Benefit Quantification of Transmission Projects

The research identified several research methods that can augment existing benefit quantification approaches to quantify the full range of transmission project benefits.

A summary of these methods is presented below.

1. Use of *Social Rate of Discount* for Calculating Present Worth of Benefits of Transmission Projects.
    - Transmission projects produce societal benefits and are a long life asset. Use of transmission is subject to open access or common carrier rules such that transmission owners cannot reserve transmission for their own exclusive use. Transmission is hence a public good and use of social rate of discount as opposed to the higher cost of capital is appropriate.
2. Fuel Diversity Benefit Quantification.
    - The marginal fuel for electricity generation is natural gas. Addition of large amounts of renewables will displace fossil fuels which, in turn, reduce cost of natural gas (price elasticity) and reduced power costs (more efficient dispatch). These benefits can be quantified and linked to large regional transmission projects.
3. Extreme Reliability Event Mitigation—Reduced Vulnerability to Multiple System Contingency Events.
    - Power systems are generally designed to meet N-1 or N-2 criteria. Extreme events, such as the August 2003 Northeast blackout and the 1996 Western Interconnection blackout were all multiple contingency events. Additional transmission projects would help mitigate the magnitude, duration, and footprint of blackouts. This can be estimated by simulating the reduction in blackout footprint from extreme events with addition of transmission.
4. Market Risk Mitigation Quantification.
    - Market prices are volatile. Societal risk tolerance to runaway market prices or market dysfunctions is limited. Individually and societally, insurance vehicles help mitigate such risks. Additional transmission will help mitigate against market dysfunction and runaway market prices.
5. Dynamic Analysis Application to Transmission.
    - Use of dynamic analysis methods to recognize changing benefit streams over the life a transmission asset can be used to quantify benefits of major new regional transmission projects.

The research also identified methods to generate stakeholder and policy consensus to value strategic benefits of transmission projects. Such methods can be used in addition to or in combination with quantification methods discussed above. The research project results identified two methods for generating stakeholder consensus.

1. Application of Delphi or Other Methods to Generate Stakeholder Consensus on Strategic Benefits.
    - Transmission project strategic benefits, such as insurance against contingencies, are not easily quantified. However, there is general acceptance that there are strategic benefits resulting from transmission projects. Application of Delphi or other methods can be used to develop consensus on level of strategic benefits

that should be assigned to transmission projects, as a percentage of total cost of the project.

2. Resource Portfolio Analysis.
   - Portfolio construction and analysis is commonly used in the financial industry to develop investment portfolios that perform well under a variety of scenarios. Portfolio analysis methods can be used to evaluate benefits of transmission projects under a variety of future scenarios and hence better inform policy and decision makers.

Methods to produce policy and stakeholder consensus such as application of Delphi and Portfolio Analysis can be used instead of the more rigorous but resource intensive quantification methods discussed above.

6.0 Application Of New Methods For Benefit Quantification

The methods listed in Section 5 above could be applied in the benefit quantification of new transmission projects, as described in the following sections.

6.1. Public Good – Long Asset Life Benefit—Use of Social Rate of Discount

Transmission projects have characteristics of providing *public good*. This can be attributed to the benefits of transmission – reliability, market efficiency, access to regional markets, meeting societal and public policy goals, and how transmission assets are used – common carrier, no property rights. Hence, it is appropriate to use a social rate of discount to calculate the present worth of benefits. Application of a social rate of discount does not require any change in methodology. However, regulatory and policy support for the concept is critical to its use and application. At a minimum, project proponents should calculate present value of benefits using both social rate of discount and traditional cost of capital to provide a perspective on the sensitivity of calculated benefits to selection of discount rate. Use of *social discount rates* to calculate present worth of benefit streams of projects which provide a *public good* rather than private property rights is well-accepted in other basic infrastructure industries, such as highway construction, wastewater treatment, dams, flood control projects, and other public interest investments.

Social discount rates more appropriately value the long term benefits that transmission projects provide to society than does current practice of reliance on the utility weighted cost of capital. This is due in part to the fact that current open access policies applicable to the transmission system mean that the benefits of new transmission lines accrue to society as a whole as the lines are now operated as common carriers. This is in stark contrast to the period prior to open access when ownership of transmission also meant reservation of use of lines by owners for private use. Today, the benefits to the transmission line owner are limited to a regulated return on invested capital.

Transmission projects have useful operating lives in excess of fifty years and benefit society at large, i.e., they are a public good. A summary of the research rationale for use of social rate of discount for evaluating transmission projects is listed below:

- Currently benefits are present-worth using cost of capital, generally in the 10% range.
- Adoption of a social rate of discount to estimate present value of benefits of transmission projects will recognize the public good nature of transmission projects.
- Transmission projects are long life—50 plus years. Benefits start to accrue as use of line increases over time. Current methods discount future benefits that occur beyond the first 10–years of project life to a point where they are not consequential.

- With a 10% discount rate, total present value of all benefits beyond 10-years in a 50-year project life is approximately 38% present worth of benefits.
- A social rate of discount, generally 3 to 5% is used to evaluate long life public works and public goods projects such as dams, roads, bridges.
- Public or societal benefits of transmission projects include fuel diversity, common carrier use, integration of renewables, insurance against extreme events, and meeting public policy goals.
- The present value of benefits using a 5% social discount rate are 60 to 70% higher than using a 10% cost of capital.

The application of a social rate of discount can be illustrated by calculating present value of benefits using different discount rates. If a project has annual benefits of $50 million, the present value of benefits over a 30-year economic life using a 10% discount rate (cost of capital) is $472 million. However, if a 5% discount rate is used (social rate of discount), the present value of the same stream of benefits is $769 million or more than 60% higher. The present value of benefits under different discount rate assumptions for a project with a 30-year life and $50 million in annual benefits are shown in Figure 2 below.

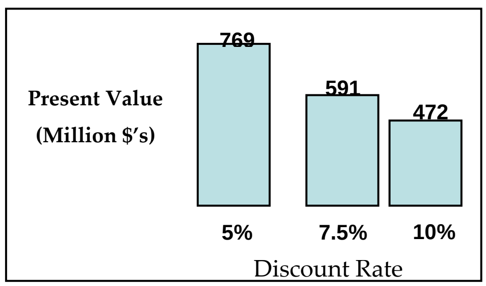

Figure 3. Present Value of Benefits Using Different Discount Rates—30-year life, $50 million Annual Benefit

The social rate of discount is a function of per capita consumption growth, the elasticity of the marginal utility of consumption and the probability of survival of the average consumer from one period to the next. For public works projects, discount rates of 3 to 5% have been used historically. For U.S., the social rate of discount is around 5%.

6.2. Fuel Diversity Benefit

For fuel diversity benefit of a transmission project, assessment is needed to quantify the amount of natural gas usage at a regional level with and without project. Then, taking into account both the decrease in the amount of natural gas used in the power system and price elasticity for natural gas, the impact of the transmission project in decreasing the price of the natural gas can be forecasted. For example, the Tehachapi Transmission Project is for the development of 4,350 MW of wind generation. Assuming an average of 35% capacity factor, the annual production from this much new wind power will be 13.3 billion kWh.

The California gross system power for 2006 shows that approximately 107 billion kWh was produced from natural gas in-state[31]. Therefore the Tehachapi Transmission Project has the potential to reduce by 12.4% the gas consumption for power production. Furthermore, gas for electric production is about 40% of total California natural gas consumption. Therefore, the impact of 4,350 MW of new wind generation will be to reduce the total natural gas consumption of California by about 4.8%.

In a recent study, the price elasticity for natural gas is estimated to be at 0.8 to 2.0%.[32] If we make a conservative assumption of 1% price reduction for 1% demand reduction for natural gas, then 4.8% reduction in natural gas consumption due to 4,350 MW of wind generation will reduce the price for natural gas by 4.8%. Assuming a gas price of $6/MMBtu, this is a reduction of $0.29/MMBtu. With wind providing 13B kWh to California and assuming no other change, electricity produced by gas will reduce from 107 billion kWh to 94 billion kWh. Assuming a heat rate of 9,000 BTU/kWh, the $0.29/MMBtu price reduction translates to an annual cost saving of about $250 million.

Figure 4 presents the above example for calculation of fuel diversity benefit.

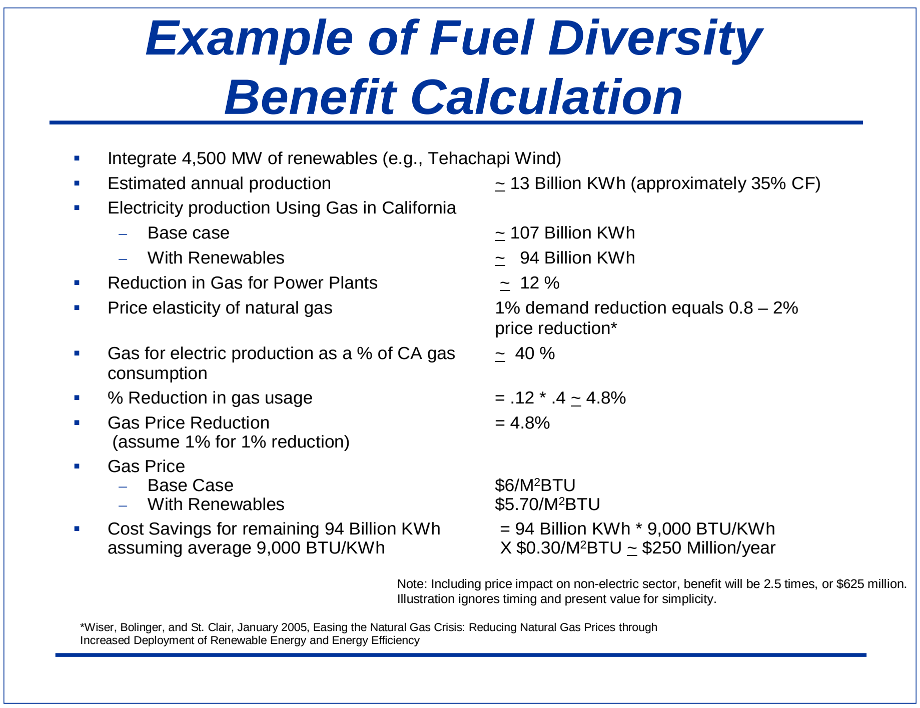

Figure 4. Example of Fuel Diversity Benefit Calculation

31. 2006 Net System Power Report, 4/12/07, Energy Commission Publication CEC-300-2007-007

32. Wiser, Bolinger, and St. Clair, January 2005, Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Development of Renewable Energy and Energy Efficiency, Ernest Orlando Lawrence Berkeley National Laboratory (LBNL-56756)

If the price reduction benefit is also assumed for gas consumed in other sectors, then this annual benefit can exceed $600 million over 30-year life of Tehachapi transmission line. The present value of this benefit using an annual discount rate of 10% will be over $6.2 billion, while the total cost of the line is estimated to be $1.8 billion.

6.3. Quantification of Reliability Improvement

Transmission system performance is usually analyzed for N-1 and N-2 events, but not for extreme cascading events. For reliability improvement from extreme multiple contingency events, research is needed to assess impact of a new transmission project in mitigating multiple cascading events contingency. This may be estimated, for example, by estimating network carrying capacity under multiple contingencies, say N-5 or N-6, and estimating load and customer loss with and without major new transmission projects.

To calculate the reliability benefit due to reduced vulnerability to extreme events, the analysis steps are as follows.

a. Develop a base model including loads, resources, transmission.
b. Define an extreme event, e.g., loss of PACI, Montana-Oregon transmission, Four Corners transmission, generation trip for a large base load unit such as Palo Verde Nuclear Power Plant.
c. Simulate an extreme event with the base case model to estimate load shedding and customer loss due to service interruptions or blackouts from extreme events.
d. Change base case by adding major new transmission lines (one or two or three).
e. Re-run model revised base case with new transmission lines and the same extreme event.
f. Estimate blackout footprint in terms of load shedding, customer loss.
g. Calculate benefit of new transmission in terms of Reduction in Load Loss *times* Economic Value of Load Loss.

This is a major analytic challenge in terms of data and resources needed for the modeling. There are many modeling and data issues: data, resources for analysis, probability of occurrence.

This approach can also be utilized retrospectively, for example in the analysis of the 2003 Northeast blackout. The estimated cost of the blackout was $5 to 10 billion[33]. If the network is simulated assuming one or more major new transmission lines, for example, American Electric Power's proposed 765 kV line, then the impact on the blackout footprint can be estimated. Assuming that the addition of major new lines reduces the simulated load loss by 40%, then, as a first approximation, the reliability benefit will be a 40% reduction of the loss or $2 to 4 billion. The steps in the application of this approach are enumerated in Figure 5.

33. U.S.-Canada Power System Outage Task Force, April 2004, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations

Quantification of Reliability Benefit Due to Reduced Vulnerability to Extreme Events – 2003 Blackout Example

- **2003 Eastern Interconnection Blackout cost $5-10 billion**
- **Network model of 2003 system**
- **Simulate blackout condition – N-n contingency**
- **Determine load loss and customer loss as determined by model – correlate with actual experience**
- **Add major new transmission lines (one or two or three)**
- **Re-run model and estimate load loss and customer loss**
- **Benefit estimate = Load Loss Reduction Ratio *times* Economic Loss Estimate of $5 to 10 billion**
- **If load loss reduced by 40%, benefit of $2 to 4 billion**

Issues: Data, resources for analysis, probability of occurrence

Figure 5. Quantification of Reliability Benefit Due to Reduced Vulnerability to Extreme Events

This quantification approach focuses on network carrying capacity under multiple contingencies with and without the new transmission project and the resulting impact of an extreme event in terms of blackout footprint.

Alternatively, a policy or expert consensus approach can be used for this benefit as being equal to a fixed percentage of project cost. This can also be estimated using the concept of reserve margins in resource planning. Generation is generally planned to a reserve margin of 15%, that is capacity should be 115% of peak load forecast. If one assumes a similar transmission reserve margin as a means of insurance against multiple contingencies or extreme events, then 15% of project costs can be assigned to benefits attributed to mitigation of extreme events. Such an approach requires further analysis and policy acceptance for application to transmission projects.

6.4. Benefit of Market Risk Mitigation

For estimating the benefit related to market volatility mitigation of a new transmission project, the analysis methodology is conceptually similar to the one outlined to quantify extreme event benefits for reliability. The analysis steps to estimate benefits of market risk mitigation due to addition of major new transmission projects are:

(a.) Define base case and estimate locational margin prices (LMPs).

(b.) Define an extreme event and rerun base case to estimate locational margin prices under extreme event.

(c.) Add new transmission lines in base case.

(d.) Estimate locational margin prices under same extreme event defined in (b) above but with new transmission lines as defined in (c).

(e.) Estimate societal value due to reduced market price spikes as measured by LMPs and resulting reduced societal cost of extreme events.

In effect, such a methodology quantifies the benefit of new transmission during extreme events by reducing congestion, market power, and price volatility.

The insurance industry utilizes extreme event probability distributions for hurricanes and earthquakes to determine insurance premium for such events. These analysis and approaches are data dependent. In the absence of such data to calculate the insurance value of avoiding extreme price volatility due to the construction of new transmission projects, a policy consensus approach may be useful. Such policy consensus can be generated via polling of policy makers or more formal approaches such as the Delphi method, value at risk and risk tolerance analysis. Consensus may translate the insurance value of a transmission project to be equal to a percentage of project cost.

6.5. Dynamic Analysis

In most production simulation models used for estimating the benefit from a new transmission project, new generic generation is added to balance load and resources. However, this *static* modeling of new generation does not take into consideration changes in generation development due to the construction of the new transmission line. There is need for dynamic planning models where the feedback from the construction of a new transmission project on the location of new generation plants would be taken into account.

Without such feedback, the amount of new generation construction in the exporting region will be underestimated and the benefit from a new transmission line understated. Furthermore, transmission projects have long life. There is need to incorporate benefits from *unanticipated* uses over the project life. This could be done based on historical experience from the construction of older transmission projects and their impact on generation expansion and interregional power trading.

For incorporating dynamic planning benefits of new transmission project, the analytical steps are:

a. Define base case for studies.
b. Estimate benefits with proposed transmission project.
c. Modify future year base case to reflect dynamic impacts, for example new generation capacity construction.
d. Estimate change in benefits.
e. Assess other dynamic factors either individually or using scenarios and weights.

6.6. Delphi Method

The challenge of addressing difficult to quantify variables has been addressed in the management science and decision analysis fields. One approach that has been used is the application of Delphi methodology. The Delphi method relies on a panel of experts to assign weights and worth (out of a total of 100) to different decision criteria or variables. The results are shared among the panel and they are offered an opportunity to reassign weights and worth based on consensus and results from the first iteration. Generally, 2 to 4 iterations result in views converging.

The Delphi approach could be adapted to assign values to different benefit categories by stakeholders or constituent groups. Benefit categories could be pre-specified, for example production costs, fuel diversity, reliability and market volatility. The stakeholders then assign values out of a total of 100 and the process is repeated in an effort to *narrow the differences* and move to a converged view that can be supported by stakeholders.

Delphi or other stakeholder consensus building could hence be utilized to incorporate societal or strategic benefits. Figure 6 illustrate the application of Delphi and stakeholder consensus approach for such an application. In the example shown in Figure 11, there is a consensus that societal benefits for this transmission project under consideration should be valued at 26.25% of the project cost. Therefore, the primary benefits from the project have to be equal or larger than 73.75% of the project cost, for this project to be economical and cost effective.

Stakeholder Consensus – Delphi Approach

- **Assemble stakeholders**
- **Define societal benefit categories, e.g.,**
  1. **Fuel Diversity**
  2. **Reliability – reduced vulnerability to extreme events**
  3. **Market Volatility – reduced incidence of runaway prices**
- **Each stakeholder to assign value to each benefit category as % of project cost**
- **Share results and repeat exercise until convergence**
- **Result – consensus on range of societal benefits to offset transmission project costs**

% Cost Reduction of Transmission Project Due to Societal Benefits

Benefit Category	Stakeholder 1	2	3	4	Average
1	5	10	10	20	11.25
2	5	5	10	10	7.5
3	5	10	10	5	7.5
Total	15	25	30	35	26.25

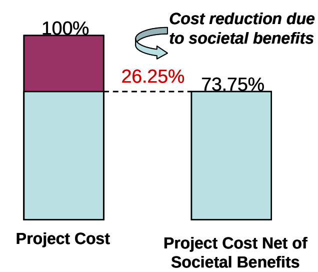

Figure 6. Stakeholder Consensus—Delphi Approach

6.7. Resource Portfolio Analysis

Transmission provides resource diversity which should help mitigate risks over a wide range of scenarios. Risk management using a portfolio approach is commonly used in financial markets.

It can be utilized in the electric power industry to develop a robust portfolio of resource options that performs well under a wide range of future scenarios.

The value of portfolio diversification is implicitly recognized in the electric power industry, but its application is generally through policy mandates such as RPS or load management goals.

The emphasis in this report has been on quantification of strategic benefits of a new transmission project, rather than on portfolio approach to planning and resource development that looks into diversification to reduce overall risk and prevent extreme costs. A portfolio approach tested against a range of future scenarios and uncertainties could be applied to generate policy consensus on need for transmission.

In the financial markets diversification and allocation of asset among different investment categories to achieve a low level of risk correlation between asset classes is the underpinning of portfolio construction to maximize risk adjusted returns. It is estimated that asset allocation can account for up to 80 percent of investment returns with market timing and individual stock selection contributing only the remaining 20 percent. This is why modern investment theory calls for portfolios based on overall risk/reward characteristics instead of that of individual stocks.

In the electric industry diversification of the supply resources has also become an important element in planning for uncertainty. Utilities, instead of concentrating their supply on one or two type of resources such as coal and oil/gas, nowadays have a portfolio of resources such as demand side management, renewable resources, nuclear, coal, hydro, and gas. In addition, the high voltage transmission system has enabled many utilities to import significant portion of their need from other utilities and/or merchant plants. Seasonal power exchanges have also provided benefit due to diverse load and resource patterns of different regions.

This resource diversification have decreased the risk due to fuel price uncertainty, performance of different types of generation resources, load uncertainty, major generation failure, and natural events such as fire, earthquake, etc. Tools used in planning for uncertainty has included scenario planning, sensitivity analysis, decision analysis and of course various probabilistic production simulation models. However, the basic element in evaluation and approval of new transmission and generation projects has been benefit-cost analysis for a specific project.

There is need to carryout research on application of modern portfolio management to determine the optimum allocation of resources into various asset categories such as demand side, different type of generation and transmission projects for import/export of energy. Correct allocation into different type of resources may be more important than precise quantification of benefit-cost of individual projects in minimizing the overall risk of meeting the needs of customers. An optimum allocation among different classes of resources, with low level of correlation, may protect the customers in an uncertain future better than selecting projects with highest benefit-cost and ending up with most of the resources being in one or two technology categories.

The primary goal in the resource planning may become the determination of optimum mix of resources of different categories. Then, within this mix, select the best projects for each category, to minimize the overall risk of the portfolio of resources.

A summary assessment of portfolio analysis as applied to the allocation of assets in an electric system is presented below:

a. Other industries, such as insurance finance, use portfolio approaches for risk mitigation.
b. Portfolio approaches depend on established historical data base to correlate variables – application to transmission requires research and data. As we gain more experience with market operations, data may becomes more available.
c. In planning for societal risk management, a diversified portfolio of resources may be more important than the precise quantification of benefit-cost of an individual project.
d. Portfolio resource diversification should be based on overall societal risk/reward characteristics instead of benefit-cost analyses of individual projects.
e. There is a need to carryout research on the application of modern portfolio management to determine the portfolio of resources such as demand side program, various generation technologies including renewable resources, and transmission to access resources from other regions.
f. Portfolio analysis steps
    - Resource allocation – mix of demand, renewables, gas, coal, nuclear, transmission
    - Resource risk – price, performance, probability
    - Portfolio performance under alternative futures.

The results of such analysis could then be used to generate policy consensus on need for new transmission that could be mandated. This will have a result similar to what happened in the case of Tehachapi transmission.

6.8. Recommendation on Use of Research Results

Figure 7 shows the areas that results from this research can be utilized. This includes: strengthening current CAISO TEAM methods, outreach to policymakers, utilization of new approaches to improve benefit quantification, support additional research on dynamic and portfolio analysis, and policy acceptance, especially the use of social rate of discount to calculate the present value of transmission projects.

Recommendation is made to augment TEAM's benefit quantification in: using social rate of discount, fuel diversity, and Delphi method for low probability/high impact and other strategic benefits. Figure 7 lists these recommendations.

Recommendations To Augment Benefit Quantification Methods

Public Good

- Use of social rate of discount to calculate the present value of benefits for the new transmission project

Fuel Diversity

- Include the benefit from potential decrease of natural gas price due to the construction of a new transmission project that integrates a significant amount of new renewable resources

Low Probability / High Impact Events

- Add risk mitigation benefit to society for low probability/high impact extreme market events and extreme system multiple contingency events – scenarios or Delphi method for stakeholder consensus

Figure 7. Recommendations to Augment Benefit Quantification Methods

6.9. Use of Improved Benefit Quantification Methods

Improved benefit quantification can be useful for:

- Calculating and quantifying the distribution of benefits among project participants and jurisdictions.
- Demonstrating and sharing benefits for direct and indirect participants and critical stakeholders.
- Enabling each utility or jurisdiction to analyze benefits of projects (or package of projects).
- Providing guidance on cost allocation among multiple participants and jurisdictions.
- Selecting cost recovery methodology.

6.10. Recommendation on Additional Research

Additional research is needed to improve transmission benefit quantification. Research areas include

a. **Dynamic Analysis**
   - Recognize the impact of new transmission projects on the construction of new generation capacity in exporting regions

b. **Portfolio Analysis**

- Adapt portfolio analysis methods utilized in the financial industry to transmission – construct and assess performance of portfolios including demand response, new generation (renewables and fuel based), new transmission, energy conservation

c. **Quantification of Extreme Event Benefits (Insurance Value)**

- Reliability – benefit of new transmission in reducing blackout footprint due to extreme (N-n) events and the societal value of reduced vulnerability
- Market Volatility -- benefit of new transmission in reducing market volatility due to extreme (N-n) events and the societal value of reduced vulnerability to run-away market prices

7.0 Cost Allocation And Cost Recovery

7.1. Framework for Cost Allocation and Cost Recovery

Cost responsibility for different types of transmission projects varies depending on the type of transmission project. Figure 8 provides a framework for who should pay for new transmission projects.

COST RESPONSIBILITY OF TRANSMISSION PROJECTS	
Type of Transmission Project	**Cost Responsibility**
▪ Requested Upgrades	Specific Requesting Party
▪ Generator Interconnection	Generator Owner
▪ Reliability	Customers of local utilities and RTO
▪ Economic	Project Beneficiaries

Figure 8. Cost Responsibility of Transmission Projects

For economic transmission projects, the goal should be to allocate costs to project beneficiaries. The principle of *beneficiaries should pay* or that *cost causers should be cost bearers* applies.

For economic transmission projects, the ownership of the project could be: the utility in whose service area the project is located, a merchant owner, or joint transmission owners when the transmission line goes through several service areas and the line in each service area is owned by the utility of that service area.

Cost recovery could be based on: transmission access charge, contract rights, subscription or auction. In an RTO, if the transmission is a reliability upgrade and is needed to maintain the integrity of the transmission grid, the costs are rolled in to the transmission charge. Costs can be rolled-in: (a) fully, (b) partially with remaining costs allocated to zones or beneficiaries, and (c) by using a voltage test and either 100% of the cost is rolled-in to an RTO wide rate or 100% into zonal rate(s).

Alternatives for cost allocation of economic type transmission projects in an RTO could be:

1. The project sponsor pays for upgrade similar to *requested upgrade*.
2. RTO recommends the cost allocation; and if the beneficiaries agree to pay for the upgrade, then the project is developed. In this method, cost responsibility among the affected load serving entities could be in proportion to their respective benefits or to their respective load shares in terms of energy or peak load.
3. RTO determines the cost allocation; and beneficiaries are obligated to pay for the upgrade.
4. *X*% of the cost is rolled into RTO base rate and the remainder of cost allocated among beneficiaries.

5. 100% of the cost is rolled into RTO base rate.

As above alternatives for cost allocation shows, the size and distribution of the project benefits may be utilized for cost allocation among beneficiaries. Therefore, improved benefits quantification will be useful in: 1) providing guidance on cost allocation among multiple participants and jurisdictions, and 2) selecting cost recovery methodology.

7.2. Cost Recovery

There are many ways to set rates for cost recovery of the transmission projects. The most commonly used method is cost of service ratemaking. This method is used by FERC and almost every state jurisdiction. The basic equation for cost of service ratemaking is:

Annual Cost = (Depreciated Rate Base x allowed weighted cost of capital) + Expenses + Taxes +Depreciation

The cost of service is then allocated over billing determinants. Currently, there are three alternative transmission rates used in different jurisdictions:

a. Energy—postage stamp.

b. Demand—annual or monthly peak demand.

c. Distance—Megawatt-mile.

Cost recovery is accomplished through rate cases that are submitted by the transmission owner (TO) utilities to the commission in each state. In addition, FERC filing may also be required to establish the rate for use of transmission. FERC has exclusive jurisdiction over transmission rates. To eliminate transmission rate pancaking (paying multiple wheeling charges for a path), FERC has been encouraging formation of ISOs and RTOs.

To stimulate the construction of new transmission lines, FERC has indicated that it will allow performance-based regulation proposals and consider innovative transmission pricing proposals including a higher rate of return on equity, levelized rates, accelerated depreciation and incremental pricing for new transmission projects.

7.3. Multiple Participants and Jurisdictions Project

Most large transmission projects provide benefits to multiple utilities that may be in single jurisdiction or sometimes in multiple jurisdictions. For example, the Tehachapi Transmission Project is being sponsored by SCE, however, all utilities in CA ISO jurisdiction will benefit from this large project as they will be able to sign contracts with wind developers in the Tehachapi area. On the other hand, the Frontier Line is likely to involve multiple utilities in multiple jurisdictions.

Figure 9 shows a framework for the use of benefit quantification for both cost effectiveness and cost allocation under single and multiple utilities and single and multiple jurisdictions.

Framework for Use of Benefit Quantification for Project Cost Effectiveness and Cost Allocation

Transmission Project

Single Utility | **Multiple Utilities**

Single Jurisdiction | **Multiple Jurisdictions**

	Single Utility	Multiple Utilities – Single Jurisdiction	Multiple Utilities – Multiple Jurisdictions
COST EFFECTIVENESS	Demonstrate cost effectiveness	▪ Demonstrate cost effectiveness	▪ Demonstrate overall project cost effectiveness ▪ Demonstrate cost effectiveness for each jurisdiction
COST ALLOCATION	Costs allocated to utility	▪ Costs allocated to all transmission customers within jurisdiction	▪ Costs allocated to each jurisdiction based on participation or benefits
COST RECOVERY	Costs recovered via rolled-in rates	Costs recovered via: a. 100% of the cost is rolled-in to an RTO wide rate b. X% of the cost is rolled-in to an RTO wide rate and the remainder to the rate of one or more zones that receive significant part of the benefits c. Using a voltage test, either 100% of the cost is rolled-in to an RTO wide rate or 100% into zonal rates	▪ Costs recovered via rolled-in rates within each jurisdiction, or x% rolled-in and remainder recovered from one or more zones that receive significant part of the benefits

Figure 9. Framework for Use of Benefit Quantification for Project Cost Effectiveness and Cost Allocation

For multi jurisdiction projects, the preferred way for the cost allocation will be first to allocate the cost to each of the jurisdictions and then allow each jurisdiction to allocate their share of cost among utilities and other users based on that jurisdiction's cost allocation methodology. Cost allocation to the multiple jurisdictions could be based on the following alternatives:

a. Participation Ratio
   - Allocate costs and MW capacity of the transmission according to participation ratio or native load ratio.

b. Subscription Open Season
   - Participation based on requested subscription (need and benefits assessment by each utility), each subscriber performs individual benefit assessment. Cost allocated based on the requested level of subscription.

c. Auction Methodology
   - This method promotes MW allocations to participants who will get the highest benefit from the utilization of the new transmission project.

7.4. Example of Auction Approach for Cost Allocation

One efficient way to allocate the use and cost of a new multi-participant or multi-jursidictional transmission project would be the auction approach.

The project sponsor or RTO can establish an auction to allocate the capacity that becomes available from a new transmission line. Participants, based on their own assessment of how much benefit they will receive from the new project, can submit bids into the auction process. Capacity of the line will be allocated to users who value this capacity most.

At least two auction methods can be designed for this capacity allocation. First is a round of ascending price auction similar to CA ISO annual FTR auction. Second is the single price and quantity bids auction.

In the first method, the auction starts for a given period with a $/MW-year payment at a level close or just below the annual revenue requirement for the project. Each period could be one year, or to encourage multi-year power contract and construction of new generation, it could be multiple of 5-years for a total of say 30-years.

If the result from the first round of bids is a total MW of bids higher than the transmission line capacity, the payment will be increased and the second round of the auction will be carried out. The auction round will be repeated until there is a balance between total bids and the online capacity available. This last round will determine the line capacity allocation amongst different parties and the payment for each MW-year.

The same auction process will then be carried out for the next period (next year or next 5-year period). This per period allocation could be repeated to cover the entire economic life of the project (or the duration for repayment of entire capital cost of the project).

Total payments generated from the auction over the periods have to be equal or greater than total revenue requirements to show that the project is cost effective. (Project sponsor has to come up with fixed revenue requirement. The project cost has, therefore, to include reasonable contingency cost. The allowed rate of return may be somewhat higher than normal allowed rate to compensate for fixed cost for the construction of the line.)

If the total payments generated in an auction are higher than the fixed revenue requirements and variable O&M cost, then the overpayments will be retained by project sponsor or RTO for decreasing the cost of grid reliability improvement projects.

If the total payments generated in an auction are not sufficient to cover the revenue requirement of the project then the project should not be developed, since the beneficiaries are not willing to pay the total cost of the project.

In the second type of auction, each bidder submits a payment and quantity for each period. Based on all bids received, a demand curve is developed for each period. The intersection of the demand curve and the capacity of the transmission line would determine the payment level for each MW and the amount of capacity to be allocated to each one of the winning bidders for this period.

The auction process is repeated for each period until the last period. Again, if the total payments are higher than the total revenue requirement, a process will be developed to use this surplus fund.

In both auctions, every participant pays the same market clearing price for a given period. The auction provides a mean to allocate the line capacity to participants who value such capacity most.

A description of the Cost Allocation Methodologies and Cost Recovery, and research recommendations are in Appendix C.

8.0 Framework For Incorporating Benefit Quantification Enhancements In Transmission Planning

Current benefit quantification methods primarily focus on quantification through use of production cost simulation type models. This tends to understate benefits as was also concluded in an October 2007 report prepared for the Australian Energy Market Commission by The Brattle Group[34].

> *Within the areas where cost-benefit tests are applied, there is a range of approaches taken to the measurement of benefits. Most systems follow a "traditional" approach that models only savings in production costs. However, it is increasingly recognised {sic} that this approach underestimates the benefits of transmission upgrades, which can also include increased reliability, enhanced competition, lower generation investment costs and other factors. The most comprehensive cost-benefit framework formally specified by a transmission planner we are aware of is the Transmission Economic Assessment Methodology ("TEAM") recently adopted by the California ISO.*

While the TEAM approach is progressive as acknowledged above, it could be further augmented to fully consider the full range of benefits of major new transmission projects.

To incorporate benefit quantification enhancements in transmission planning, the following framework is proposed.

1. Strengthen current methods such as TEAM.

   The CA ISO TEAM method has been developed over a period of time. This could be strengthened as follows:

   a. Incorporate use of social rate of discount in calculating present value of benefits. This will more explicitly recognize the *public good* aspect of transmission projects, including long asset life benefit.
   b. Explicitly calculate fuel diversity benefit and reflect that in benefit calculations.
   c. Pending research dynamic analysis and quantification of extreme event benefits, utilize a stakeholder consensus approach to assign value to these strategic benefits. Such a value could be developed using a formal Delphi approach, or scenario analysis, or less formal stakeholder consensus.
2. Initiate research into use of dynamic analysis approaches that could then be used to strengthen current methods.
3. Initiate research into development of resource portfolios that perform well under a wide range of scenarios and contingencies. Results of resource attributes of the low risk

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34. The Brattle Group, October 2007, International Review of Transmission Planning Arrangements, – A report for the Australian Energy Market Commission, page 6.

portfolio could be used to develop public policy consensus on need for new transmission, for example to access renewables and other markets.

4. Initiate research on quantifying extreme event benefits (Value at Risk, Insurance Premium, and other methods).

9.0 Project Outreach and Briefings

The research project benefited from feedback and guidance received formally and informally during the project. The following briefings and presentations were made during the project.

A. Technical Advisory Committee (TAC). The TAC was convened in-person twice during the research project. These meetings took place January 19, 2007 and September 10, 2007. In addition, TAC was consulted informally on key issues and provided briefings and draft report for review, comment and feedback.

B. Briefings were made to the Frontier Line team twice during the research project.

C. Consortium for Electric Reliability Technology Solutions (CERTS) Industry Advisory Board was briefed on the project at its regularly scheduled meeting on November 8, 2007.

D. The CA ISO management and staff briefing on February 27, 2008.

E. The CPUC briefing on April 23, 2008.

F. Briefing for Western Electricity Coordinating Council Transmission Expansion Planning Policy Committee on June 12, 2008.

G. Briefing for the Energy Commission management and Commissioner Byron on July 2, 2008.

The CPUC has a current proceeding "Order Instituting Investigation (OII) on the Commission's Own Motion to actively promote the development of transmission infrastructure to provide access to renewable energy resources in California. The CPUC's Division of Ratepayers (DRA) filed a motion in March 2008, to supplement the record in that proceeding to "…consider and discuss the ongoing quantification analyses being done under the auspices of the Transmission Research Program of the Public Interest Energy Research (PIER) Program administered by the California Energy Commission (CEC), entitled *Strategic Benefits Quantification of Transmission Projects*. The particular documents DRA wishes to make a part of the record are: (1) *Project Introduction Briefing, Strategic Benefits Quantification of Transmission Projects*, presented by Virgil Rose, Senior Advisor, at the California Public Utilities Commission, April 23, 2008; (2) *Consortium for Electric Reliability Solutions, Strategic Benefits Quantification for Transmission Projects,* Electric Policy (sic) Group, project briefing for the California Public Utilities Commission, April 23, 2008."

DRA's motion can be viewed by clicking this link: http://docs.cpuc.ca.gov/efile/MOTION/84041.pdf.

10.0 Utilization of Research Results

The benefits of this research will be realized through use of research results. This can be done in transmission projects being considered in California and the Western grid. There are three key elements. The first is application of the research to strengthen benefit quantification methods used in California, for example, CA ISO's TEAM approach. Second is the wide spread sharing of research results through outreach and participation in different transmission forums to discuss, debate and refine the proposed methods. Third is additional research on benefit quantification methods such as portfolio analysis, dynamic planning, and extreme event benefit quantification. Fourth is to advocate more transparent, inclusive and predictable planning processes. A summary of uses of research results is presented below:

1. *Strengthen Current Benefit Quantification Models, for example, by augmenting CA ISO TEAM and other methods.*
2. *Brief stakeholders on benefits quantification methods and how to utilize new approaches for improved benefits quantification.*
3. *Initiate research to improve benefits quantification, recognition, and sharing.*
4. *Promote transparent planning processes, for example, by supporting CA ISO efforts for more transparency stakeholder participation and to standardizing planning process.*

11.0 Key Conclusions And Research Recommendations

11.1. Recommendations for Benefit Quantification

1. Social Rate of Discount:

   Since the transmission system has become a *public good*, the use of social rate of discount, instead of allowed weighted cost of capital, to calculate the present worth of benefits of a new transmission project is recommended.

2. Screen Tools:

   In early stages of the project, the use of a screening tool similar to the one developed by PG&E for application to the Frontier Line (FEAST) can be very productive. Simple spreadsheet-based tools will enable and empower project participants to carryout a variety of analyses quickly, with the goal of developing and testing the benefit of multiple alternatives. Spreadsheet tools are useful screening devices but are not a substitute for detail production costing simulation for detailed benefit analysis. They are, however, useful to perform quick what-if screening analysis and can test the impact of the various types of benefits and risks.

   Screening and current production cost simulation tools are capable of quantifying primary benefits and some of the strategic benefits of a new transmission project. The main missing benefit quantifications are:

   - Risk mitigation for low probability/high impact extreme market events.
   - Reliability improvement from extreme multiple contingency events.
   - Fuel diversity benefit due to impact of significant renewable resources development upon price of natural gas.
   - Dynamic impact of transmission projects in the development of new generating plants in the exporting region.

i. Additional Research

   Initiate research into development of resource portfolios that perform well under a wide range of scenarios and contingencies. Results of resource attributes of the low risk portfolio could be used to develop public policy consensus on need for new transmission, for example to access renewables and other markets.

   Initiate research into use of dynamic analysis approaches that could then be used to strengthen current methods.

   Furthermore, initiate additional research on quantification of societal benefits of transmission in providing insurance value against extreme events that are low probability/high impact events.

Strengthening current TEAM:

The CA ISO TEAM method has been developed over a period of time. This could be strengthened as follows:

a. Incorporate use of a social rate of discount in calculating present value of benefits. This will more explicitly recognize the *public good* aspect of transmission projects, including long asset life benefit.
b. Explicitly calculate fuel diversity benefit and reflect that in benefit calculations.
c. Pending research dynamic analysis and quantification of extreme event benefits, utilize a stakeholder consensus approach to assign value to these strategic benefits. Such a value could be developed using a formal Delphi approach, or scenario analysis, or less formal stakeholder consensus.

11.2. Recommendations for Cost Allocation and Cost Recovery

In economic transmission projects, the principle of *beneficiaries pay* should be the basis for cost allocation.

Attempts should be made to quantify primary and strategic benefits of transmission projects in a transparent way so that project participants and beneficiaries can agree on the level of benefits and who gets what share of these benefits and who pays what share of the costs.

If there is too much uncertainty in forecasting the size and distribution of benefits and/or some of the important strategic benefits are difficult to quantify, then it may not be possible to develop a consensus amongst beneficiaries on size and distribution of benefits. This may be especially true with projects where there are multiple utilities and multiple jurisdictions.

To solve this difficult problem, three alternative approaches could be utilized:

Alternative	Description
a. Participation Ratio	Costs and MW of transmission capacity are allocated according to participation ratio or native load ratio
b. Subscription Open Season	Participation is based on requested subscription. Each subscriber performs individual benefit-cost assessment.
c. Auction	It is based on willingness to pay approach and on benefits assessment by each entity. May result in revenues in excess of costs. Such excess revenues are used for reliability improvement projects or reallocated among participants. Auction promotes MW allocation to participants with highest benefit.

There may be cases that exporting region, owners of surrounding area of right-away, or some of the participants are negatively impacted by the construction of a new transmission line. This may happen even if strategic benefits are included in the analysis. In such cases, *side payments* to negatively impacted parties may be justified. These *side payments* could be in from of improvement/construction of some infrastructures such as roads, parks, sport facilities, and electrical reliability improvement projects.

If an auction is utilized to allocate the capacity of the new transmission project, the revenues from the auction will usually exceed project costs if the benefits are larger than costs. Such excess revenues can be utilized for *side payments* or the cost of new infrastructure as side payments.

Glossary

CCGT	Combined Cycle with Combustion Turbines
CO_2	Carbon Dioxide
CT	Combustion Turbine
CERTS	Consortium for Electric Reliability Technology Solutions
CPUC	California Public Utility Commission
CSRTP	CA ISO South Regional Transmission Plan
DPV2	Devers-Palo Verde No. 2
DRA	Division of Ratepayer Advocates, CPUC
EPG	Electric Power Group
FEAST	Frontier Economic Analysis Screening Tool
FERC	Federal Energy Resources Commission
FTR	Firm Transmission Rights
GDP	Gross Domestic Product
GHG	Greenhouse Gas
IGCC	Integrated Coal Gasification Combined Cycle
ISOs/RTOs	Independent System Operators/Regional Transmission Operators
LMPs	Locational Margin Prices
PG&E	Pacific Gas and Electric Company
RPS	Renewable Portfolio Standard
SCE	Southern California Edison
SONGS	San Onofre Nuclear Generation Station
TAC	Transmission Access Charges
TEAM	Transmission Economic Assessment Methodology TEAM
TO	Transmission Owner
WECC	Western Electricity Coordinating Council
WRTEP	Western Regional Transmission Expansion Partnership

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Appendices

Appendix A

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Appendix B

Benefit Assessment Methodologies

1.0 Current Methodologies For Benefit Quantification

1.1. Types of Projects

All transmission projects have attributes that relate to reliability, economics, and operations. However, the processes that are used for economic evaluation and cost recovery of projects varies depending on the type of project, and for this purpose, transmission projects are generally grouped into four categories:

- Requested Upgrades.
- Generation Interconnection.
- Reliability (Base Plan Upgrades).
- Economic (Supplemental Upgrades).

Requested Upgrades are projects that meet specific request or requirements of a customer and are usually paid by the customer.

Generation Interconnection is to connect a new power plant to the electrical system and is usually paid by the generator. There may also be need for system upgrade as a new significant generator is being added to the system.

Reliability projects are transmission improvement that may be required to satisfy the existing or new reliability criteria. Without such a transmission, there is potential for reliability related problems and failure to meet the established reliability criteria.

Research indicates that the first three types of projects—requested upgrades, generation interconnection, and reliability projects have clear drivers or mandates and tend to go forward with little or no opposition. However, economic projects (including projects that address specific policy objectives such as renewables integration and debottle-necking) often get stymied due to different perspectives on need, benefits, and cost responsibility.

The economic projects are proposed to reduce the total cost to society. This includes economic projects that are used for reducing bottlenecks and congestion, expanding access to regional markets, meeting policy goals such as Renewable Portfolio Standards (RPS), and providing insurance against multiple contingencies.

In this research, the emphasis is on methods that can be used to quantify benefits and allocate costs of Economic (Supplemental Upgrade) transmission projects. The research results are applicable to other types of projects and to projects that exhibit multiple dimensions of economics, reliability, and operations.

1.2. Types of Benefits

The benefits from an economic transmission project can be grouped into:

- Primary Benefits (Traditional Benefits).
- Strategic Benefits.

- Extreme Event Benefits.

There are also secondary benefits from new projects. These include: economic development, tax base increase, use of right-of-way, and impact on infrastructure development. These secondary benefits are not addressed in this study.

Primary or traditional benefits can be defined as cost reduction, congestion reduction and expansion of access to regional markets to take advantage of load and resource diversity. Primary benefits improve network reliability and result in lower cost of energy and capacity adjusted for transmission losses.

Strategic benefits can include:

- Access to new renewables resources to meet Renewable Portfolio Standard (RPS).
- Promote efficient market operation and market power mitigation.
- Promote fuel diversity.
- Provide emission reduction/environment benefits.
- Improve deliverability.
- Insurance against contingencies.
- Meet policy goals such as Renewable Portfolio Standard.

These strategic benefits all contribute to lower cost electricity or risk for consumers, and if properly quantifies, will show larger streams of benefits of transmission projects than what has traditionally been quantified.

There are also secondary benefits from new projects. These include: economic development, tax base increase, use of right-of-way, and impact on infrastructure development. These secondary benefits are not addressed in this study.

The types of benefits of new transmission projects depends on whether the region is at the generation or exporting end or importing end of the transmission line. Benefits accruing to a region are a function of location with respect to a transmission line as follows:

- Exporting Region Benefits
  - Regional economic development.
  - Increase tax base.
  - Reliability Improvement.
  - Expansion of generation resources.
- Importing Region Benefits
  - Import of lower cost energy and capacity.
  - Reliability improvement.
  - Strategic benefits:

        - Access to renewables.
        - Fuel diversity.
        - Emission reduction.
        - Insurance against contingencies.
        - Increased deliverability.
        - Decrease *Market Power*.
    - Exporting and Importing Region Benefits
        - Seasonal exchange.
        - Sales of surplus energy.
        - Reserve sharing.
        - Reliability improvement.

There are many uncertainties that impact the size of primary benefit and types of strategic benefits from a new project. These uncertainties include load forecast, fuel prices, development of new generation and retirement of existing power plants, regional prices for electricity, and environmental regulation. Production cost-simulation, scenario analysis, stochastic modeling, and other techniques have traditionally been utilized to estimate a base level of benefit and the sensitivity analysis to take into consideration future uncertainties. These models tend to come up with base case, sensitivity cases, and expected value of benefits.

Another category of benefits relates to extreme events. In recent years, the August 2003 Northeast Blackout and the California 2000–01 market dysfunction put a spotlight on the significant economic (billions of dollars) and societal impact of such extreme events. The challenge is that traditionally, there has been no attempt to quantify the benefit of mitigating extreme events or when it is done, an expected value approach is utilized which understates the societal value of mitigating these very low probability but very high impact events.

One of the research conclusions is that insurance against extreme events be defined as additional societal benefit for reducing exposure to extreme market volatility and multi-region-wide blackouts due to multiple contingencies. While there is general consensus on the existence of these types of strategic benefits, they are not easily quantified or captured using traditional models. For example, policymakers anecdotally acknowledge the value of transmission projects as insurance against contingencies, but there is no definition or examples of quantification of such values.

The above category of benefits can be defined as Extreme Event Benefits and are in addition to the Primary and Strategic Benefits. The value of extreme event benefits can be put in context when some of recent power system experiences are examined. For example:

- 2001 California market dysfunction and volatility with a cost of $20-40 billion.
- 2003 Northeast Blackout due to multiple contingencies with a cost of $5-10 billion.

Extreme Event Benefits can be defined as:

3. Reliability—which is based on improved network load carrying capacity and ability to reduce or mitigate impact of extreme events resulting from multiple contingencies (N-3, 4, 5, 6 events).
4. Market Volatility—which is based on societal benefit of reduced vulnerability to extreme price volatility which could result from extreme system events, market dysfunction, or a combination of factors.

Society's willingness to buy protection against extreme events is well established in the insurance industry, for example hurricane insurance, life insurance, re-insurance against major losses. In each of these examples, there is a well established actuarial data base that allows valuation of such insurance. However, there is not a rich data base related to extreme events in the electric power industry as major blackouts and market dysfunctions are infrequent events. Hence, the research challenge is to come up with alternative approaches that address these benefits rather than dismiss them due to difficulty in quantifying them.

1.3. Benefits Assessment Approaches in Use

The transmission project benefit quantification approaches in use include:

- Production Simulation Models.
- Decision Analysis Models.
- Screening Analysis Models.
- Tipping Point Analysis.

These approaches are discussed briefly in this section and in Appendix B.

For economic benefit quantification of new transmission projects, the basic approach is to utilize a Production Simulation Model. The analysis includes two alternatives: one with and another without the proposed new transmission project. Many commercial production simulation models are available, such as PROSYM, GEMAPS, PROMOD, and PLEXOS. Using a least cost dispatch principle, the models forecast production from different generation resources and associated fuel consumption, and emissions. To have a balance between loads and resources, additional generation resources are also introduced over time. Based on fuel prices, costs of various emissions and variable O&M costs, the total production cost over time are calculated for a given load forecast and associated load shape. The difference in the total production costs from the two simulations defines the gross benefit for the new transmission project.

The net benefit of the transmission project is then calculated by subtracting the capital cost and annual O&M of the transmission project from the estimated gross benefit. Benefit cost ratios and internal rate of return can also be calculated from the information provided by the annual production costs, capital, and O&M expenditure of the transmission project.

To take into consideration the uncertainty of factors such as fuel costs, load forecast, and capital cost of the transmission project, Decision Analysis Models have been utilized to estimate the expected value and the distribution of net benefit or benefit cost ratio. These may also utilize Influence Diagrams that shows the factors that have great impact on benefits and costs of the project.

Carrying out detailed production cost simulation with and without project are data intensive, time consuming, and expensive. This becomes more difficult when the detail of transmission network is included in the model in addition to the generation system. Furthermore, information on planned new generation development is based on market economics and data is generally not available beyond 5 to 10 years, while transmission projects are expected to last 50-years or more and deliver benefits during the entire period.

At the pre-feasibility level the use of a Spreadsheet Screening Analysis may facilitate studying many transmission options quickly and at less time and expenditure than using detail production simulation models. An example of this approach will be discussed later when the benefit-cost analysis of Frontier Line is reviewed.

Spreadsheet Screening Analysis is useful when new generation resources at export region plus a new transmission is compared with new generation resources at import region. This approach allows comparison of many alternatives quickly. The results provide forecast of fuel consumption, emission, and variable O&M and fixed O&M costs. Benefit and cost of a new transmission is then calculated based on such information for different alternatives by including capital costs of generation at export and import regions, fuel prices and capital cost of the transmission project.

To concentrate the analysis on assumptions and relationships that greatly influence the project benefits, the use of Tipping Point Analysis method is sometimes utilized. In applying this method, an economic criterion for the project is established. Potential tipping points which are associated with key variables are listed and tested. The level of tipping point where benefit/cost is less than one are determined and the potential for ending up with benefit/cost less than one are evaluated and discussed for these tipping points.

1.4. Review Of Benefit Analysis Of Some Recent Projects

CA ISO's existing and proposed transmission planning process and case histories of recent projects are in Appendix F.

In this section, the analytical tools and benefits quantification methods for benefit analysis for three different projects are discussed. The three projects are Devers-Palo Verde No. 2 (DPV No. 2), Tehachapi, and Frontier Line.

1.4.1. Devers-Palo Verde No. 2

Economic evaluation of Devers-Palo Verde No. 2 has been carried out and reviewed by many parties, including CA ISO, SCE, Division of Ratepayer Advocates (CPUC), and Consortium for Electric Reliability Technology Solutions/Electric Power Group (CERTS/EPG) for Energy Commission.

SCE's objectives for proposed construction of DPV No. 2 are to:

- Increase California's access to low-cost energy from the Southwest.
- Enhance competition among generating companies supplying energy to California.

- Provide additional transmission infrastructure to support the development of additional generation capacity that will sell energy into California market.
- Provide increased reliability and flexibility in operating California's transmission system.

SCE has used a production cost simulation model (PROSYM) to estimate energy cost saving resulting from the construction of DPV No. 2. This project is estimated to decrease electricity prices in California, which is the primary benefit of this project. There will also be additional third party transmission revenue due to increased CA ISO wheeling through or out of the CA ISO grid.

Southern California Edison evaluation shows a B/C ratio for DPV No. 2 at 1.7. Energy benefits are based on production cost simulation for 2009–2015 and then escalated at GDP price index (around 2.28% per year) for the rest of economic life of the project.

At the request of CA ISO, SCE has provided energy production cost for Western Electricity Coordinating Council (WECC) for the years 2009 through 2014 with and without DPV No. 2. Using the cost saving numbers provided by SCE for WECC, the present value of the quantified benefits from energy and third party transmission revenue is less than the capital cost of DPV No. 2, using a 5% discount rate.

The WECC regional benefit for this project is low, in part, because strategic benefits such as insurance value during extreme system conditions, reduction in generators market power, potential for development of new generation outside of California and environmental benefits beside NO_x reductions are not quantified in WECC regional benefit calculation.

CA ISO has used its Transmission Economic Assessment Methodology (TEAM) approach and PLEXOS cost production simulation model to quantify the benefits from DPV No. 2. Benefits include cost saving in energy, transmission loss reduction, emissions reduction, market power mitigation, and contingency. CA ISO's proposed methodology for benefit quantification of the transmission projects address the following major issues: modeling of market power; development of a robust set of scenarios; selection of appropriate simulation tools or programs; a detail representation of the transmission network and the assumptions of the future generation system; and, selection of benefit tests. Detailed description of these elements is provided in a report prepared by Consortium for Electric Reliability Technology Solutions/Electric Power Group for the Energy Commission in June 2004[35].

Benefit tests examined by the CA ISO includes:

- The participant/ratepayer test (benefits to those entities that will be paying for the new facility).

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35. Consortium for Electric Reliability Technology Solutions/Electric Power Group, June 2004. Economic Evaluation of Transmission Interconnection in a Restructured Market, California Energy Commission (CEC-700-04-007), pages 10-12.

- The societal test (benefits to all consumers, producers, and transmission owners, regardless of who pays for the upgrades).
- The modified societal test recognizing or excluding non-competitive revenues (monopoly rent) collected by some producers.

The societal test is measured by the change in production costs across the entire interconnection (in case of DPV No. 2 over the entire WECC). A transmission expansion project is deemed to pass the benefit test if: 1) it benefits each participant, and 2) the entire societal or the modified societal benefit exceeds the project cost.

The WECC base case data is the foundation of the CA ISO modeling. CA ISO's PLEXOS model of the entire WECC requires significant amounts of input data. Due to the limited available CA ISO staff time for the collection of input data for each year, CA ISO modeling for the economic analysis of DPV No. 2 was done only for two years—2008 and 2013.

CA ISO in its quantification of DPV No. 2 benefits included:

- Operational benefit—such as saving from generation unit commitment costs, minimum load compensation and redispatch of units to address real-time transmission congestion.
- Capacity benefit—such as utilization of some of the surplus capacity in Arizona.
- Loss savings – reduction in transmission losses as a result of DPV No. 2 operation, which were not captured in the DC Power Flow Model.
- Emission reduction—the emission were not directly modeled in the production simulation model.

In the CA ISO evaluation, the above benefits were significant portion of the total benefits[36].

CA ISO's goals in the development of Transmission Economic Assessment Methodology (TEAM) have been[37]:

- Development of a common methodology to evaluate economic need for transmission upgrades.
- Presenting a framework that will be useful in making effective decision on transmission investment.
- Providing transparency in methods, databases, and models so a variety of stakeholders can understand the implications of a transmission upgrade.

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36. CA ISO Department of Market Analysis and Grid Planning, February 2005, Economic Evaluation of the Devers-Palo Verde No. 2.

37. Transmission Economic Assessment Methodology (TEAM), Anjali Sheffrin, June 14, 2004. California Energy Commission IEPR Workshop on 2004 Transmission Update.

CA ISO filed TEAM with CPUC in June 2004. CA ISO has demonstrated in actual studies the use of TEAM for Path 26 and DPV No. 2. The methodology clearly indicates impacts of a new upgrade at the participants' level and also regional (WECC) levels.

Several new elements identified in this research could be added to TEAM to further expand quantification of benefits, such as:

- Extreme event benefits such as improve network load carrying capacity under multiple contingencies.
- Reduced vulnerability to extreme price volatility due to long term outages and catastrophic events.
- Dynamic impact of a large transmission projects on the development and construction of additional generation capacity in the exporting region.

By adding the above benefits to TEAM, the methodology will be able to capture the benefits from risk mitigation of low probability/high impact extreme market events and the benefits of development of new generation to both exporting and importing region. Without taking into consideration such dynamic impacts, the analysis becomes a zero-sum game whereby there are higher electricity prices in the exporting region with the implication that the investment in a transmission line has negative impact on consumers of the exporting region. In fact, this factor contributed to the recent rejection of DPV No. 2 by the Arizona Corporation Commission.

Division of Ratepayer Advocates at CPUC has also carried out a review of the DPV No. 2. This report was prepared in three volumes that were published in November 2005. Volume 3 of this study describes the Tipping Point Analysis for DPV No. 2[38].

As described by Dr. House in his DRA Testimony, *Tipping Point* analysis has gained popularity in the social sciences since Gladwell's 2000 book, *How Little Things Can Make a Big Difference*[39]. The analysis starts with defining the topology of the interactions (similar to the Influence Diagram in Decision Analysis). Then through some analysis it is determined which interactions are critical to the outcome (tipping points).

Dr. House's analysis shows that tipping point variables for the DPV No. 2 project are:

- Natural gas price differential between Arizona and California.
- Generation resource plan in Arizona.
- Palo Verde Nuclear Plant outage.
- Wholesale natural gas prices.

Based on analysis performed, the following conclusions were reached:

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38. Testimony of Lon W. House, November 22, 2005, *Tipping Point Analysis and Attribute Assessment for DPV No. 2*, Office of Ratepayer Advocate's Devers Palo Verde No. 2 Testimony Vol. 3 of 3.

39. Malcolm Gladwell, 2000, *The Tipping Point: How Little Things Can Make a Big Difference*, Little Brown and Company, New York.

> "In order for DPV2 to be cost effective, the natural gas price differential between Arizona and California has to be greater than $0.50/MMBtu, the wholesale Topoc price of natural gas has to be greater than $5.00/MMBtu and Palo Verde (Nuclear Generation Station) has to be operating."[40]

Furthermore, DPV No. 2 is more valuable to California in the event of an outage of San Onofre Nuclear Generation Station (SONGS).

Tipping Point Analysis provides clear information on critical variables and allows the analyst to concentrate on high impact factors rather than spend a great deal of time and effort on elements that do not materially change the outcome of the analysis.

1.4.2. Tehachapi Transmission Project

Tehachapi Transmission Project is designed to access wind generation resources in the Tehachapi area along with associated system upgrades beyond the first point of interconnection. SCE is the project sponsor. The goal is to develop transmission that will be the *least-cost* solution to reliably interconnect 4,350 MW of generating resources in the Tehachapi Area Generation Queue to the CA ISO grid.

In addition, the project also addresses the reliability needs of the CA ISO controlled grid caused by load growth in the Antelope Valley area, as well as transmission constraints South of Lugo.

The main benefit of this project is to enable California utilities to buy power from wind generation projects and to comply with the state mandated Renewable Portfolio Standard (RPS) program.

The project justification for Tehachapi is renewable resource integration and reliability. While resource integration has an economic dimension, the project justification is based on meeting state RPS mandates rather than benefit cost analysis. The Tehachapi project evolved from the Tehachapi Collaborative Study Group, which was formed in 2004 at the direction of CPUC. The goal was to develop a comprehensive phased transmission development plan for integration of renewables planned for development in the Tehachapi area. Two reports were issued and submitted to CPUC in March 2005 and in April 2006. The outcome was the identification of a number of alternatives for the transmission infrastructure. A recommendation was made to further study these alternatives by the CA ISO.

The CA ISO in full collaboration with SCE and stakeholders carried out the Tehachapi Transmission Project study as part of its CA ISO South Regional Transmission Plan for 2006 (CSRTP-2006). A least-cost solution for the interconnection of planned generation was developed by CA ISO.

The total cost of the Tehachapi Transmission Project is estimated at $1.8 billion in nominal dollars. This cost excludes the cost of Interconnection Facilities (radial wind collector transmission systems that will interconnect the individual generation projects to the grid and

40. Reference 5, Page 38.

will be the responsibility of generation developers). SCE is the Project Sponsor and the project is subject to necessary regulatory approvals from CPUC and FERC, *which have either been received or expected*.

The Tehachapi Transmission project phased development plan includes:

- Antelope - Pardee, 230 kV line and Antelope Substation Expansion.
- Antelope-Vincent 230 kV Line #1, 500 kV.
- WindHub Substation.
- Antelope-Wind Hub 230 kV line, 500 kV.
- Antelope-Vincent 230 kV Line #2, 500 kV.
- Low Wind 500/230 kV Substation with loop-in of Midway-Vincent #3 500 kV line.
- Antelope-Low Wind 500 kV line.
- WindHub Substation 500 kV Upgrade.

One or more of the transmission line segments may be characterized as bulk-transfer gen-tie for an interim period of time until additional lines and transmission interconnections are built. For these lines, characterized as bulk transfer gen-tie lines, generators would be charged a pro-rata rate for transmission service over the gen-tie line. The residual revenue requirement for any unsubscribed portion of the gen-tie line would be recovered either from retail ratepayers under CPUC-approved rate or from all transmission customers in FERC-jurisdictional Transmission Access Charges (TAC) rates. If any of these bulk-transfer gen-tie lines are later converted into a network facility, then generators would be relieved of their pro-rata share of the transmission service charge respectively.[41]

CA ISO has used the concept of *clustering* in the Tehachapi Transmission Project. *Clustering* allows study the system impacts of a group of interconnection requests collectively, rather than evaluate each potential generation project one at a time. This results in greater efficiency in the design of needed network upgrades.

The clustering approach for the Tehachapi Transmission Project will result in substantial capital cost saving compared to any piecemeal upgrade solution with a traditional project by project approach.

However, in Tehachapi Transmission Project, the CA ISO has deviated from a typical clustered interconnection study. The CA ISO study considered only the network components or network upgrades of the transmission system and excluded the radial wind collector transmission systems. Furthermore, an element of clustering is the selection of a time window for determining which generation projects in the queue will be included in the cluster (i.e., the *Queue Cluster Window*). The Tehachapi Transmission Project defined the Queue Cluster

41. Armie Perez, Vice President of Planning and Infrastructure Development, January 18, 2007, Memorandum to CA ISO Board of Governors, Page 6.

Window as the projects submitted from August 19, 2003 through April 2006, which exceeds FERC limit of 180 days for the Queue Cluster Window.

Due to the specific circumstances presented by Tehachapi Project, CA ISO has filed a petition with FERC for approval to proceed with the proposed study approach on a one-time basis.

CA ISO Board has approved the Tehachapi Transmission Project as the Network Upgrades necessary to allow Generating Facilities in the Tehachapi Wind Resources Area to deliver their output to CA ISO grid. The Board has directed SCE to proceed with the permitting and construction of this project. FERC's approval of the CAISO waiver request for provisions of Large Generator Interconnection Procedures (LGIP) allowed this project to move forward.

1.4.3. Frontier Line

The Western Regional Transmission Expansion Partnership (WRTEP) is proposing the construction of Frontier Line, a large transmission project between Wyoming, Utah, Nevada, and California.

To perform a screening level economic study, the Economic Analysis Subcommittee developed a spreadsheet tool to quantify benefits and costs of multitude of possible alternatives and scenarios. These alternatives included: a variety of load and resources scenarios, a myriad of conceptual transmission links and configurations identified by the Transmission Subcommittee; a wide range of natural gas prices and possible costs for new clean coal technology, including integrated gasification combined cycle (IGCC) and carbon dioxide sequestration; and a broad spectrum of potential policy actions such as regional and/or national renewable portfolio standards, state and federal tax incentives for preferred resources such as wind or solar or clean coal, and regulatory regimes in greenhouse gas emissions.

To carryout these benefit-cost analysis in a transparent manner, the Economic Analysis Subcommittee designed and constructed a unique analytical tool, the Frontier Economic Analysis Screening Tool (FEAST). The intent was to develop an analytical tool to enable the Economic Analysis Subcommittee to carryout analysis at a screening level which will provide an understanding of the ranges of assumptions under which the development of the Frontier Line will be cost effective and for which more detailed economic analysis using a detailed system production cost simulation will be warranted.

FEAST is a simple tool for knowledgeable users. It considers incremental resource additions, not a complete supply stack which would include all the existing generators.

For this screening analysis, the Gross Benefits ($) of the transmission project is based on the following formula:

Gross Benefit =	Energy Potential	X Line Utilization	X Regional Basis
	MWh	(%)	$/MWh

Energy Potential is the rated capacity of the line multiplied by 8,760 hours. For example, if the Frontier Line is rated 3,000 MW, then energy potential would be 3,000x8760 or 26,280 GWh per year.

Line Utilization is a function of the quantity and characteristics of resources available to be imported as compared to the line's energy potential. (Basically, capacity of generation resources installed in exporting region multiplied by assumed capacity factors for each resource and subject to the transmission line and system constraints.)

Regional Basis is the energy cost difference between the exporting region and the importing region. This Regional Basis is influenced by many factors, including the capital cost of new generation resources, fuel costs (gas, coal, and others), environmental mitigation costs, renewable energy price premiums, Green House Gas (GHG) adders, and others.

Benefits in addition to energy benefits include: capacity, losses, emissions, insurance value against extreme events, economic impacts due to construction of transmission and generation facilities, tax benefits, reliability improvement and others.

Many of the subcommittee members provided input on fuel prices, capital cost for generation, ranges for Green House Gas adder, capacity factor for wind energy in different regions, and other assumptions. The FEAST Spreadsheet Model was developed by staff of PG&E.

FEAST can handle several exporting regions (source options): Wyoming and Montana (coal and wind), and several importing regions (sink options), including Utah, Nevada, Arizona, and California. Resources considered for importing regions can be gas-fired CT or CCGT or IGCC and renewables (for Utah coal, gas, renewables). For exporting regions, resources can be wind and/or clean coal.

A mix of generation resources for exporting and importing regions are assumed. Taking into consideration capacity and capacity factor of these generation resources, the amount of energy going from source to sink is calculated.

FEAST is an energy focused analysis. Attempt is made to balance energy produced from the generation resources in the sinks and sources. The installed capacity of generation ends up being different for sinks and sources.

The Economic Analysis Subcommittee performed its work using a participatory stakeholder process. Volunteers led the effort to create FEAST inputs. Individual subcommittee members were able to perform their own analysis based on some of their own inputs.

The final report of this subcommittee was submitted to Western Regional Transmission Expansion Partnership (WRTEP) on April 27, 2007[42]. Two most important conclusions of the report were:

3. The benefits of the Frontier Line appear greater than the costs under a variety of plausible scenarios.
4. Uncertainty associated with key inputs results in a wide range of benefit-cost outcomes.

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42. Economic Analysis Subcommittee for Western Regional Transmission Expansion Partnership, Final Report April 27, 2007, *Benefit-Cost Analysis of Frontier Line Possibilities*.

The economics of the Frontier Line, as expected, are very sensitive to natural gas prices and the values used for GHG adder. Economics of the Line are also somewhat sensitive to capital costs for clean coal technologies, including IGCC and CO_2 sequestration.

The primary focus of the analysis that was carried out by the Economic Analysis Subcommittee was economic efficiency from a total societal point of view, i.e., the analysis produced the overall benefit-cost ratio for the region as a whole. Of course, it is important that the Frontier Line produces benefit for each individual jurisdiction participating in the project, i.e., benefit be greater than cost for each state. The Economic Analysis Subcommittee did not analyze cost allocation so that each jurisdiction participating receives a net benefit from the project. However, FEAST enables each user to perform its own analysis and assess benefits and costs allocated.

As stated in the Final Report of the Benefit-Cost Analysis of Frontier Line, FEAST is not a substitute for production costing simulation tools. Analysis using FEAST may be a first step to quickly sort through a multitude of possibilities. FEAST is a tool to perform quick what-if screening analysis. It is a simple spreadsheet-based tool enabling and empowering sophisticated users to carryout a variety of analyses quickly, with the aim of developing user insight rather than producing overly precise numerical results[43].

1.5. Benefit Analysis Observations And Conclusions

The three projects reviewed for benefit analysis are representative of a wide range of potential future large regional transmission projects. A summary of the projects analyzed is presented in Figure APB- 1.

43. Reference 9 p 8.

Summary of Benefit Analysis of Transmission Projects

Project	Description	Purpose	Comments
Palo-Verde Devers No. 2	▪ 500 kV line between Arizona and California ▪ Single utility and single rate jurisdiction (CA ISO) ▪ $500 million cost ▪ 1,300 MW capacity	Reduce California electricity costs	▪ Benefits to California estimated using production cost and sensitivity analysis ▪ Strategic and regional benefits not addressed ▪ Static analysis – assumed generation capacity fixed
Tehachapi	▪ Designed in several phases to interconnect 4,350 MW of new wind generation ▪ Required CA rate back-stop and innovative CA ISO tariff to allocate costs ▪ $1.8 billion cost ▪ Costs allocation among generator (gen-tie), CA ISO grid users, and CA ratepayers for cost recovery back-stop	Enable integration of new wind generation in CA ISO queue to meet RPS	Least cost solution to meet RPS mandate.
Frontier Line	▪ 500 kV ▪ 3,000 MW ▪ $2 billion cost ▪ Multi-state, multi-utility, multi-jurisdiction	Designed to enable construction of new generation in Wyoming/Montana for export to CA, NV, UT, AZ	▪ Benefits estimated using screening model – FEAST ▪ Benefits result from cost differential (capital and fuel) between resources developed in CA vs. WY/MT ▪ Strategic benefits not quantified ▪ Strong state government support in exporting regions ▪ No strong utility project sponsor

Figure APB-1. Summary of Benefit Analysis of Transmission Projects

Of the three projects, Tehachapi is moving forward. Palo Verde-Devers No. 2 was rejected by the Arizona Commission and SCE, the project sponsor, is moving ahead

to construct the California segment of the transmission line and continuing to pursue approval from FERC for the Arizona portion. Frontier Line is still in the conceptual planning stages.

From this review, the following observations and conclusions are presented.

4. Elements of successful projects, e.g., Tehachapi
   - Strong project sponsorship.
   - Extensive stakeholder participation.
   - Clear objectives and benefits, whether quantifiable or not.
   - Cost recovery certainty.
   - Policy and regulatory receptivity.
5. Benefit quantification
   - Primary methods used are production simulation or screen methods.
   - Benefits are based on cost differentials for different options, i.e., project vs. no project or comparison of different project options.
   - Many strategic benefits were not quantified.

- Analysis required data intensive assumptions about future loads, resources, fuel prices, and policies.

6. Problems encountered by projects

   - Limited showing of benefits for key stakeholders, e.g., Palo Verde-Devers No. 2.
   - Ambiguity about objectives and goals, including changing policies, e.g., Frontier Line.

Appendix C

Cost Recovery and Cost Allocation Methodologies

1.0 Cost Allocation And Cost Recovery

1.1. Framework for Cost Allocation and Cost Recovery

Cost responsibility for different types of transmission projects varies depending on the type of transmission project. Figure APC-1 provides a framework for who should pay for new transmission projects.

COST RESPONSIBILITY OF TRANSMISSION PROJECTS	
Type of Transmission Project	**Cost Responsibility**
▪ Requested Upgrades	Specific Requesting Party
▪ Generator Interconnection	Generator Owner
▪ Reliability	Customers of local utilities and RTO
▪ Economic	Project Beneficiaries

Figure APC-1. Cost Responsibility of Transmission Projects

For economic transmission projects, the goal should be to allocate costs to project beneficiaries. The principle of *beneficiaries should pay* or that *cost causers should be cost bearers* applies.

For economic transmission projects, the ownership of the project could be: the utility in whose service area the project is located, a merchant owner, or joint transmission owners when the transmission line goes through several service areas and the line in each service area is owned by the utility of that service area.

Cost recovery could be based on: transmission access charge, contract rights, subscription or auction. In an RTO, if the transmission is a reliability upgrade and is needed to maintain the integrity of the transmission grid, the costs are rolled in to the transmission charge. Costs can be rolled-in: (a) fully, (b) partially with remaining costs allocated to zones or beneficiaries, and (c) by using a voltage test and either 100% of the cost is rolled-in to an RTO wide rate or 100% into zonal rate(s).

Alternatives for cost allocation of economic type transmission projects in an RTO could be:

6. The project sponsor pays for upgrade similar to *requested upgrade*.
7. RTO recommends the cost allocation; and if the beneficiaries agree to pay for the upgrade, then the project is developed. In this method, cost responsibility among the affected load serving entities could be in proportion to their respective benefits or to their respective loads share in terms of energy or peak load.
8. RTO determines the cost allocation; and beneficiaries are obligated to pay for the upgrade.
9. *X*% of the cost is rolled into RTO base rate and the remainder of cost allocated among beneficiaries.
10. 100% of the cost is rolled into RTO base rate.

As above alternatives for cost allocation shows, the size and distribution of the project benefits may be utilized for cost allocation among beneficiaries. Therefore, improved benefits quantification will be useful in: 1) providing guidance on cost allocation among multiple participants and jurisdictions, and 2) selecting cost recovery methodology.

1.2. Cost Recovery

There are many ways to set rates for cost recovery of the transmission projects. The most common used method is cost of service ratemaking. This method is used by FERC and almost every state jurisdiction. The basic equation for cost of service ratemaking is:

Annual Cost =	(Depreciated Rate Base X allowed weighted cost of capital)	+ Expenses + Taxes +Depreciation

The cost of service is then allocated over billing determinants. Currently, there are three alternative transmission rates used in different jurisdictions:

d. Energy—postage stamp.

e. Demand—annual or monthly peak demand.

f. Megawatt—mile.

Cost recovery is accomplished through rate cases that are submitted by the transmission owner (TO) utilities to the commission in each state. In addition, FERC filing may also be required to establish the rate for use of transmission. FERC has exclusive jurisdiction over transmission rates. To eliminate transmission rate pan caking (paying multiple wheeling charges for a path), FERC has been encouraging formation of ISOs and RTOs.

To stimulate the construction of new transmission lines, FERC has indicated that it will allow performance-based regulation proposals and consider innovative transmission pricing proposals including a higher rate of return on equity, levelized rates, accelerated depreciation and incremental pricing for new transmission projects.

1.3. Multiple Participants and Jurisdictions Project

Most large transmission projects provide benefits to multiple utilities that may be in single jurisdiction or sometimes in multiple jurisdictions. For example, the Tehachapi Transmission Project is being sponsored by SCE, however, all utilities in CA ISO jurisdiction will benefit from this large project as they will be able to sign contracts with wind developers in the Tehachapi area. On the other hand, the Frontier Line is likely to involve multiple utilities in multiple jurisdictions.

The figure below shows a framework for the use of benefit quantification for both cost effectiveness and cost allocation under single and multiple utilities and single and multiple jurisdictions.

Framework for Use of Benefit Quantification for Project Cost Effectiveness and Cost Allocation

Transmission Project

Single Utility / **Multiple Utilities**

Multiple Utilities: **Single Jurisdiction** / **Multiple Jurisdictions**

	Single Utility	**Single Jurisdiction**	**Multiple Jurisdictions**
COST EFFECTIVENESS	Demonstrate cost effectiveness	▪ Demonstrate cost effectiveness	▪ Demonstrate overall project cost effectiveness ▪ Demonstrate cost effectiveness for each jurisdiction
COST ALLOCATION	Costs allocated to utility	▪ Costs allocated to all transmission customers within jurisdiction	▪ Costs allocated to each jurisdiction based on participation or benefits
COST RECOVERY	Costs recovered via rolled-in rates	Costs recovered via: a. 100% of the cost is rolled-in to an RTO wide rate b. X% of the cost is rolled-in to an RTO wide rate and the remainder to the rate of one or more zones that receive significant part of the benefits c. Using a voltage test, either 100% of the cost is rolled-in to an RTO wide rate or 100% into zonal rates	▪ Costs recovered via rolled-in rates within each jurisdiction, or x% rolled-in and remainder recovered from one or more zones that receive significant part of the benefits

Figure APC-2. Framework for Use of Benefit Quantification for Project Cost Effectiveness and Cost Allocation

For multi jurisdiction projects, the preferred way for the cost allocation will be first to allocate the cost to each of the jurisdictions and then allow each jurisdiction to allocate their share of cost among utilities and other users based on that jurisdiction's cost allocation methodology. Cost allocation to the multiple jurisdictions could be based on the following alternatives:

a. Participation Ratio
   - o Allocate costs and MW capacity of the transmission according to participation ratio or native load ratio.

b. Subscription Open Season
   - o Participation based on requested subscription (need and benefits assessment by each utility), each subscriber performs individual benefit assessment. Cost allocated based on the requested level of subscription.

c. Auction Methodology
   - o This method promotes MW allocations to participants who will get the highest benefit from the utilization of the new transmission project.

1.4. Example of Auction Approach for Cost Allocation

One efficient way to allocate the use and cost of a new multi-participant or multi-jurisdictional transmission project would be the auction approach.

Project sponsor or RTO can establish an auction to allocate the capacity that becomes available from a new transmission line. Participants, based on their own assessment of how much benefit they will receive from the new project, can submit bids into the auction process. Capacity of the line will be allocated to users who value this capacity most.

At least two auction methods can be designed for this capacity allocation. First is a round of ascending price auction similar to CA ISO annual FTR auction. Second is the single price and quantity bids auction.

In the first method, the auction starts for a given period with a $/MW-year payment at a level close or just below the annual revenue requirement for the project. Each period could be one year, or to encourage multi-year power contract and construction of new generation, it could be multiple of 5-years for a total of say 30-years.

If the result from the first round of bids is a total MW of bids higher than the transmission line capacity, the payment will be increased and the second round of the auction will be carried out. The auction round will be repeated until there is a balance between total bids and the online capacity available. This last round will determine the line capacity allocation amongst different parties and the payment for each MW-year.

The same auction process will then be carried out for the next period (next year or next 5-year period). This per period allocation could be repeated to cover the entire economic life of the project (or the duration for repayment of entire capital cost of the project).

Total payments generated from the auction over the periods have to be equal or greater than total revenue requirements to show that the project is cost effective. (Project sponsor has to come up with fixed revenue requirement. The project cost has, therefore, to include reasonable contingency cost. The allowed rate of return may be somewhat higher than normal allowed rate to compensate for fixed cost for the construction of the line.)

If total payments generated in auction are higher than the fixed revenue requirements and variable O&M cost, then the overpayments will be retained by project sponsor or CA ISO for decreasing the cost of grid reliability improvement projects.

If total payments generated in an auction are not sufficient to cover the revenue requirement of the project then the project should not be developed, since the beneficiaries are not willing to pay the total cost of the project.

In the second type of auction, each bidder submits a payment and quantity for each period. Based on all bids received, a demand curve is developed for each period. The intersection of the demand curve and the capacity of the transmission line would determine the payment level for each MW and the amount of capacity to be allocated to each one of the winning bidders for this period.

The auction process is repeated for each period until the last period. Again, if the total payments are higher than the total revenue requirement, a process will be developed to use this surplus fund.

In both auctions, every participant pays the same market clearing price for a given period. The auction provides a mean to allocate the line capacity to participants who value such capacity most.

Appendix D

Technology Options and Implications and Their Impacts

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Executive Summary

There are several options for transmitting energy from remote generation resources to the various load centers within the Western Interconnection. The amount of energy to be transmitted and the overall distance become key factors as to which of the options becomes more desirable, as is the impact that a new transmission project will have on the existing WECC grid. The following is a recap of the research findings:

- The use of new technology conductors appear to be best utilized and cost effective in the integration of new or upgraded transmission lines into urban transmission networks.
- Superconducting cables appear to also be best utilized in urban areas, especially where extremely high capacity underground transmission is required.
- The use of High Voltage Alternating Current (HVAC) (765 kV) transmission would allow for the movement of bulk power over great distances. This new technology is in-service in the Eastern Interconnection and performing as anticipated. Because there is no existing 765 kV infrastructure within the WECC, adding a single 765 kV line (to deliver 3,000 MW) would have a negative impact on grid stability and unscheduled flow. Developing the supporting infrastructure to integrate 765 kV into the western grid would have some significant costs consequences.
- To use 500 kV AC (to deliver 3,000 MW), two lines would be required to carry large amounts of energy (500 kV AC lines are typically rated at 1200-1600 MW/line). This option will require additional Right-of-Way.
- Utilization of Variable Frequency Transformers (VFT) and Phase Shifting Transformers has the ability to protect the rights of participants when AC transmission options are used.
- Utilization of Flexible AC Transmission System (FACTS) is expected to be an essential element of all future AC transmission lines to ensure grid reliability, and can assist in managing the flow of power over specific lines in a transmission network.
- At this time, to transmit 3,000 MW of energy, or higher over long distances (over 400 to 500 miles), the most cost effective method is the implementation of a High Voltage Direct Current (HVDC) line for the following reasons:
    - HVDC affords the ability to explicitly control the power flow on the transmission lines
    - HVDC will not negatively impact unscheduled flow.
    - HVDC is isolated from AC system faults.
    - HVDC system multi-terminal converters could be utilized if multiple pick-up and drop-off points are required. This technology is available and in-service today.

HVDC can be integrated with the AC system to create a hybrid form of transmission. This option provides a HVDC link over the longest line section to a central delivery facility at which point the project participant(s) can take delivery into their respective AC system. This option eliminates the need for multi-terminal converters.

1.0 Introduction

The need for investments in transmission infrastructure and new technologies has been accepted for some time. In recent years, this has translated into policy support for new transmission projects. Recently, there has been much discussion regarding the construction of new EHV transmission lines in the Western Interconnection. The governors of California, Nevada, Utah and Wyoming had proposed a new interstate EHV transmission line across the Western U.S., from Wyoming with terminal connections in Utah, Nevada and California. Some of the Arizona utilities and others are considering an EHV transmission project from Wyoming to the Desert Southwest area, and PG&E has proposed an EHV project from British Columbia to Northern California. Within California, projects in the various stages of planning and regulatory approval include Palo Verde Devers No. 2, Tehachapi, Transbay cable, Greenpath, and Sunrise.

Such new transmission projects would provide the necessary links to new and diverse generating resources, such as renewable and clean coal resources. The development of any of these new transmission projects in the Western Interconnection would bring the following benefits:

- Strengthen the reliability of the Western Interconnection.
- Better protect consumers from energy shortages and price spikes.
- Encourage a broader, diversified energy portfolio.
- Reduce reliance on foreign energy imports and enhances domestic energy security.
- Encourage the use of new generation technology that would accelerate the development of renewable energy resources and reduce the cost of controlling emissions from the West's vast fossil fuel resources.

The Federal Energy Act signed August 8, 2005 has also encouraged several transmission technological advancements (e.g., high ampacity conductors). Industry offerings and research and development of new transmission technologies for flow control, voltage support, smart grid, hybrid D.C., phase shifting transformers, superVar (synchronous condensers using superconductors) are on the rise. With these new innovative products, the market has better ways to transport energy to the consumers.

The purpose of this research is to review available technologies and assess implications on cost allocation and cost recovery for new infrastructure investments.

Construction of new EHV transmission lines between the various sub-regions of the Western Interconnection is being driven by the following four (4) needs:

- Demand for electricity in high-population states in the West is projected to grow significantly in the coming decades. However, sitting generation near the load is increasingly difficult and costly. Tapping into abundant renewable resources and clean coal electricity in the Intermountain West will help keep the West's economy growing and will reduce price pressures on consumers.

- California faces a significant need for new generation. Using a historic growth rate of 2% per year, California must add 1,000 MW of new capacity each year, net of retirements, into the foreseeable future. New transmission lines into California are essential in meeting that need. In addition, California needs to find new renewable resource supplies to meet the State mandated Renewable Portfolio Standard (RPS).
- As a region, the West has seen load growth of more than 60 percent in the last 20 years, but investment in high-voltage transmission lines increased less than 20 percent. Investment in new EHV transmission, besides providing a pathway to new generation resources, will ease existing transmission bottlenecks and enhance the overall reliability of the region.
- New EHV transmission lines provide an insurance benefit that will help mitigate the impacts of adverse hydro conditions, fuel price volatility, and potential market power abuse and better ensure against catastrophic events like blackouts.

One of the key implications for cost recovery and cost and benefit allocation is the capability of any proposed transmission project to dependably deliver power over the intended transmission path(s). Electric power flows according to physical laws, not contract laws, and as such, power moves over the transmission lines that offer the lowest resistance (impedance) between the source generators and the load. The ability to manage and control new power deliveries to travel over the facilities designed and installed to accommodate those deliveries is expected to significantly affect the ability of the project developers to allocate costs and benefits among the project participants, and to assure that the participants are able to recover their costs through dependable power deliveries, while not adversely affecting adjacent transmission systems. Technologies that can deliver the benefits of new investment to the owners are likely to influence debates regarding cost allocation.

This review of transmission technologies examines the several options from the perspective of their ability to increase power deliveries and manage the flow of power.

The U.S. electricity transmission system is an essential component to our nation's economic vitality.

Within the Western Interconnection, the investment in new transmission facilities has declined over the past few decades, the customer demand is increasing and there is the continuing need to operate a reliable grid. The expansion of the electricity delivery system is crucial to the region's economic and security. In addition, the transmission system is vital to supporting an ongoing competitive wholesale electricity market and in achieving the states Renewable Portfolio Standards.

The objective of this report is to identify how the use of new transmission technology may impact the operation of new transmission facilities and cost allocation of a project. In order to effectively discuss the role of advanced transmission technologies, consideration must be given to how they can be deployed in the grid and their functionality.

1.1. Conductors

Heat is the prime enemy of conductors. The more power that is pushed through them, the more they heat and sag, and it is sag and clearance that ultimately determine maximum conductor loading.

The manufacturers of conductors have, with the assistance of the 2005 Federal Energy Act, developed new conductors that can be loaded to higher current levels by reducing the sag component of their conductors.

The current carrying capacity or ampacity of a conductor is directly proportional to the cross-sectional area of the conducting material. This cross sectional area is usually measured in square inches. In the late 1800s, the U.S. electric industry standardized conductor sizing by agreeing to use circular mils for measuring the cross-sectional area of conductors. A circular mil is the area of a circle with a diameter of one mil (0.001 inch). The abbreviation of circular mils is cmil. There are 1,273, 200 circular mils in one square inch. For conductors having a cross-sectional area smaller than or equal to 211,600 circular mils, the industry elected to adopt the Brown and Sharpe wire gage designated in 1857, what we now call American Wire Gauge (AWG). The area of a large conductor is often designated in kcmil (thousand circular mils) rather than cmil. For example, the cross-sectional area of 4/0 AWG is 211,200 cmil or 211.2 kcmil.

1.2. ACSR – Aluminum Conductor Steel Reinforced

Used as bare overhead transmission conductor and as primary and secondary distribution cable, ACSR has been the industry standard overhead conductor for many decades. ACSR offers optimal strength for line design variable zinc coated steel core stranding enable desired strength to be achieved without sacrificing ampacity. This conductor consists of a solid or stranded steel core surround by strands of aluminum. This conductor is available in a wide range of steel content varying from as low as 6% to as high as 40%. The higher strength ACSR conductors are used for long spans, overhead ground wires, etc. ACSR conductor can be manufactured for a wide range of tensile strength as required. The principle advantage of this conductor is high tensile strength, light weight and relatively low cost.

1.3. AAC – All Aluminum Conductor

This conductor is also known as aluminum stranded conductor. This conductor is manufactured from electrolytic ally refined aluminum, having purity of minimum 99.5% of aluminum. This conductor is used in urban areas where the spacing is short and the supports are close. All aluminum conductors are made up of one or more strands of aluminum wire depending on the end usage. This conductor is also used extensively in coastal areas because it has a very high degree of corrosion resistance.

1.4. AAAC – All Aluminum Alloy Conductors

AAAC is a high strength aluminum alloy, concentric-lay-stranded conductor. It is similar in construction and appearance to the AAC all aluminum conductor.

This conductor is made from aluminum-silicon alloy of high electrical conductivity containing enough magnesium silicide high strength aluminum alloy[44] to give it better mechanical properties after treatment. These conductors are generally made out of aluminum alloy 6201.

This conductor as compared to the industry standard ACSR has the advantage of lower power losses (the inductive effects of the steel core in the core is eliminated), excellent corrosion resistance in environments conducive to galvanic corrosion, better strength to weight ratio, improved electrical conductivity than ACSR of equal diameter and greater resistance to abrasion than that for Type 1350 aluminum used for ACSR. The two conductor types (AAAC and ACSR) are similar in that the fittings are the same and the sag characteristics are similar.

1.5. ACSS - Aluminum Conductor Supported Steel

This High Temperature, Low Sag (HTLS) Solution has a temperature operating range of up to 250°C (482°F) with reduced sag (compared to ACSR). This allows the line the capability of transmitting 50 to 70% more current than conventional ACSR Transmission conductors. The difference is in the temper of the aluminum wires. The aluminum wires used to make conventional ACSR are in the fully work hardened temper; where as those used to make ACSS are fully annealed[45]. The ACSS trapezoidal conductor consists of concentric-lay stranded products consisting of steel central cores that are multi-layered with 1350-0 aluminum wire. The ACSS/TW conductors contain up to 25% more aluminum in the same diameter compared to conventional ACSR cable, resulting in increased ampacity.

The ACSS conductor can operate continuously at high temperatures without any detriment to its mechanical properties. It will sag significantly less at high temperatures than ACSR conductors when the maximum tension is present under ice and wind loading. The sag-tension performance of ACSS is not affected by long time creep of aluminum. This material has a high capability for damping mechanical oscillations, such as those associated with wind vibration. It also has a high degree of immunity to vibration fatigue.

The ACSS aluminum wire strands are annealed, giving them low yield strength. Because of their low yield strength, inelastic elongation of the aluminum strands occurs quite rapidly when tension is applied to the conductor, thereby forcing most of the load onto the steel core. The designation "Aluminum Conductors – Steel Supported" derives from the fact that under most normal operating conditions there is little or no stress in the aluminum wires and even under maximum tension there is minimal reliance on the strength of the aluminum.

ACSS aluminum is soft; some additional emphasis must be given to normal precautions to avoid scuffing of the surface during installation and maintenance. When used to replace the

44. 6201 T81 aluminum alloy

45. http://www.generalcable.com/NR/rdonlyres/0F57D894-A202-4423-8750-BD348E7B9581/0/UTY0006R0603.pdf

same size ACSR this conductor is normally heavier and thus requires higher tension and can result in tower modification. It is also higher cost than ACSR.

Both new ACSS products have a full line of sizes. ACSS sizes range from 266.8 kcmil to 2312 kcmil; ACSS/TW conductor sizes range from 477 to 2627 kcmil.

1.6. ACCR – Aluminum Conductor Composite Reinforced

3M Aluminum Conductor Composite Reinforced (ACCR) delivers two to three time the power while utilizing the same tower configuration as today's standard ACSR conductor . ACCR is already in service at several locations in North America. This conductor provides two to three times higher ampacity with less thermal expansion (sag) than conventional conductors of similar size. The major difference between ACCR and other conductors are due to the differences in the core materials. The outer strands portion of the 3M ACCR conductor relies on aluminum-based materials. The core is a revolutionary aluminum matrix composite material that has the strength and stiffness of steel with a lower coefficient of thermal expansion and less weight.

3M ACCR's core is composed of aluminum composite wires, surrounded by hardened temperature-resistant aluminum-zirconium. ACCR has a continuous operating temperature rating of 210°C and an emergency temperature rating of 240°C. In contrast, Aluminum Conductor Steel Reinforced is rated to 100°C continuous, 150°C emergency.[46]

Installation of the ACCR is similar to that of conventional ACSR conductor. Listed below are the locations where this conductor is already installed or being installed.

The installation of this new family of conductors has a few differences in the methods of installation as compared to the standard ACSR. The pulling of the conductor requires, in most cases, larger rollers at the tower. For instance, in a recent installation of the 3M ACCR, 3M provide the first roller from the pulling dolly, and recommended the use of larger rollers (28 inch) at each tower (note: the larger rollers are readily available). The splice is made with a special process and splice kit. The kit is also provided by the manufacturer, as is an on-site technical advisor.

1.7. ACCC – Aluminum Conductor Composite Core

The Composite Technology Corporation claims that its product doubles the current carrying capacity of the conventional ACSR conductor. The conductor has a low sag ratio to heat as compared to the standard conductor. This lighter material reduces the number of towers or poles required. CTC claims "On average, a new (ACCC) line at the same height can eliminate 16% of the structures required."[47] This product is cheaper than 3M's ACCR conductor and not as brittle as the ACCR. The splicing and pulling of this conductor is similar to the existing ACSR conductor.

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46. System Analysis, Inc., Application Guides – Equipment Damage Curves Conductors, 2006, www.skm.com

47. Electric Transmission Week, November 2004 "Two new transmission cables reaching market; China seen as strong opportunity

Even though this material is new, it is making an impact in the industry since its introduction. A 2004 news release reporting on a reconductor project indicated "This initial installation in the city of Holland, Michigan utilized over three thousand feet of ACCC conductor."[48]

China is purchasing 175 miles of the ACCC to be delivered in the first quarter of 2007.

ACCC has a core made of a carbon fiber composite. The outer layer is softer aluminum with a trapezoidal strand design. The rated operating temperature is 180°C, with a recommended short term maximum operating temperature of 200°C. The glass transition temperature (Tg)[49] of the core is 215°C. At temperatures above the Tg, the properties of the core change and strength is affected.

1.8. Superconducting Cables

Superconductivity was first discovered in 1911 in mercury, and regained notoriety in 1986 with the discovery of new ceramic materials that could provide the benefits of superconductivity at temperatures of liquid nitrogen. Superconductivity is now widely used in medical imaging (MRI) today, and is also being deployed into the electric grid to solve local power problems.

High temperature superconductor (HTS) wire enables power transmission and distribution cables with three to five times the capacity of conventional underground AC cables and up to ten times the capacity of DC cables. They support general load growth, add controllability of power over a meshed grid, and can be implemented with low environmental impacts.

Benefits of the technology include:

- High power with low loss, increased efficiency, reduced CO2
- No EMF emissions, no heating and no oil (for cooling) provides low environmental impact
- Thermal independence, no backfill required and deep borings OK.
- Dis-location of step-down transformer from load bus.
- Small cross sections, retro-fitting ducts.

The central component of the superconductor power cable is HTS wire that can conduct 150 times the electrical current of copper of the same dimensions. Many strands of HTS wire are wound onto the cable assembly in a coaxial configuration that produces essentially zero electric and magnetic field emissions (EMF).

The inherently low impedance of this type of cable assembly enables control of power flows over the surrounding grid network. Liquid nitrogen, the dialectic and coolant of choice to

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48. Composite Technology corporation News Release August 30, 2004

49. Glass Transition Temperature (Tg) is that temperature where a polymer when cooled below that temperature the polymer becomes hard and brittle like glass.

maintain the HTS wire at its operating temperature, is inexpensive, abundant and environmentally safe, eliminating the oil used in some conventional power cables.

Superconducting cables are ideal solutions for grid bottlenecks. In addition to enabling more effective transmission and distribution of energy, superconducting cables are also inherently able to regulate the power flow through the cable. As an HTS Cable overload begins, the superconducting HTS wire begins to overheat, reducing its superconducting properties, increasing its resistance, and hence reducing the power flow through the cable.

HTS Cables are "out of the lab" and being deployed in multiple projects in the grid, including 4 US projects (Albany, NY; Long Island, NY; and Columbus, OH; and Carrollton, GA) as well as at other locations around the world.

The capabilities of HTS superconducting cables suggest that the most practical applications will be in urban settings where greater underground power delivery capabilities are required than can be supported by conventional cables.

In addition to its cable application, HTS superconductors are effectively used in dynamic reactive power compensation modules, such as SuperVAR Synchronous Condensers, Dynamic VAR Compensators, and Distributed Superconducting Magnetic Energy Storage Systems (D-SMES). These are devices that make use of superconducting windings in synchronous condensers or superconducting magnets to provide technology that can dynamically inject or absorb reactive power to regulate grid voltages and enhance grid stability. The first SuperVAR Synchronous Condenser was installed in December of 2003 in the TVA system.

Superconducting motors and generators are also being developed and deployed.

Today, the application of superconducting VAR devices is primarily focused on the distribution system, but these devices could be used to provide dynamic voltage support to the EHV grid to enhance grid stability and power delivery capability.

1.9. Conclusion - Conductors

As with most electrical components, the conductor is rated based on heat. The ability of an overhead conductor to dissipate the heat generated from the flow of electrons through the strands of the conductor is an important element in rating the conductor. The heat generated from the current flow is a squared function of current -- I^2R. As the current doubles, the heat generated increases by a factor of four. Another characteristic changed by heat in the conductor is its length. A conductor will elongate as its temperature increases. The problem for a line designer is that as the conductor elongates the amount of sag increases. For a typical line (336 ACSR with a 300 foot ruling sag), the elongation caused from heating a conductor from 95° F (35° C) to 122° F (50° C) is 1.16 inches. This elongation results in an increase sag of 3.29 feet. Using the same conductor and increasing the temperature from 122° F (50° C) to 167° F (75° C), the elongation is 1.93 inches and the increase in sag is 4.25 feet. This elongation results in additional slack in the span and less clearance to ground at the mid-point of the span, thereby limiting the power rating of the line.

The new higher temperature conductors could have a very significant impact on the utility industry around the country and the world. It allows utilities to revisit their needs knowing that there are feasible alternatives that can be implemented to tackle their demand. Even though these new conductors have a greater current carrying capacity, they appear to be better suited for upgrading transmission lines in urban areas than in new transmission line construction, because of the high cost of the advanced conductors.

	ACSR[50]	**AAC[51]**	**AAAC[52]**	**ACSS[53]**	**ACCC[54]**	**ACCR[55]**
Core	Galvanized Steel	Conductor	Conductor	Steel	Carbon & Glass Fiber	Aluminum Matrix Composite
Outer conductor	Aluminum Alloy	Aluminum Alloy	Aluminum Alloy	Annealed Aluminum	Aluminum Alloy	Aluminum Zirconium
795 kcmil Weight/kFt	1094 lbs	745 lbs	865 lbs	1040 lbs	891 lbs	896 lbs
% Ampacity Increase over ACSR	--	-3%	0%	50-70%	100%	100%
Operating Temp.	75 °C	75 °C	75 °C	250 °C	180 °C	210 °C

50. Aluminum Conductor Steel Reinforced

51. All Aluminum Conductor

52. All Aluminum Alloy Conductor

53. Aluminum Conductor Steel Supported

54. Aluminum Conductor Composite Core

55. Aluminum Conductor Composite Reinforced

2.0 Unscheduled Power Flow

Generated power is scheduled to flow on transmission lines according to transaction schedules between control areas. Typically, a schedule entails a point-to-point transfer of power or energy over a specific transmission path. However, because of physical laws like Kirchhoff's laws and Ohm's law, when there are parallel AC transmission paths between the source generation and the load, the scheduled power may not flow on the transmission path designated in the transaction schedule. This represents a deviation from the desired or scheduled flow. This deviation between the actual power flow in a circuit and the scheduled flow is called Unscheduled Flow (a.k.a. loop flow). Unscheduled flows are the flows occurring along a route parallel to the scheduled path and can have adverse effects on the wide area system and the owners of other transmission paths. Unscheduled flows are an unavoidable phenomenon in wide area AC interconnected power networks. The issue of unscheduled flow has been classified as the single most difficult problem of interconnected operations in the WECC history.[56] Unscheduled flow essentially deals with the difference in real power in transmission circuits and not the reactive power. It is common practice in the electric industry for each participating utility to be directly responsible for their power flow associated with their generation. The problem with unscheduled flow is that as hundreds or thousands of simultaneous transactions are imposed upon the transmission system, mutual interference develops, potentially producing congestion. This congestion may limit some entities from being able to fully utilize their transmission assets and cheaper sources of energy.

Controlling power flow in one or more of the various parallel AC transmission lines would permit more effective use of transmission resources. Conventional devices for power-flow control include series capacitors to reduce line impedance, phase shifters, and fixed shunt devices that are switched to the end of a line to adjust voltages. All of these devices employ mechanical switches, which are relatively inexpensive and proven but also slow to operate and vulnerable to wear, which means that it is not desirable to operate them frequently and/or use a wide range of settings; in short, mechanically switched devices are not very flexible controllers. Nonetheless, they are still the primary means use for stepped control of high power flows.

There could be several of types of unscheduled flows occurring in an interconnected system and they can have certain potentially undesirable effects on system operation. There are flows in the interconnection that do not manifest themselves in loops but exist as individual flow. These are popularly termed as inadvertent power flows and occur when a balancing authority fails to adequately balance its loads and resources on an ongoing basis.

The following sections will discuss the various transmission components and technology that provides the capability for flow control on both AC and DC transmission grids.

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56. http://www.ornl.gov/~webworks/cppr/y2001/misc/122375.pdf

2.1. Phase Shifters

As discussed above, the fundamental characteristic that makes transmission planning and investment so difficult is the lack of control of the power flows over the grid and the inability to control the flow through individual transmission elements. Devices such as phase shifters and direct current (DC) links allow control, but are much more expensive than traditional AC transmission facilities. Each transmission element is part of a network that is a common resource available to all. Phase shifters are used in many applications.

2.2. Phase Shifting Transformers

Existing transmission systems are often operated and stressed to the limit of their performance capability. To ensure that under these conditions the economical, reliable and secure operation of the grid is maintained, the need for various aspects of power flow management within the power systems becomes evident. Phase-shifting transformers help control the real power flow in transmission lines and systems interties. The main benefits of phase-shifting transformers include the protection of lines and transformer from thermal overload and an improvement of transmission system stability. They allow controlling the power flow between different systems, for parallel long distance overhead-lines for parallel circuits.

Phase shifting transformers (PST) are used to control the flow of real power in transmission lines by manipulating the phase angle difference. The phase angle shift is obtained by combining the voltages from different phases in the PST. Phase-shifting transformers, when combined with standard capacitors and reactors, can even provide control of reactive power and fault current limitation.

The natural impedance and phase angle differences in a network often lead to unscheduled flow. Phase-shifting transformers redirect the power flow, allowing existing lines to be loaded closer to their thermal limits.

2.3. Variable Frequency Transformer

General Electric has developed a new Variable Frequency Transformer (VFT). The VFT is a controllable, bidirectional transmission device that, similar to PST, can control the real power flow in transmission lines and systems interties, but the greatest advantage is that it allows power transfer between two networks that might not be synchronized. The VFT is essentially a continuously variable phase-shifting transformer that can operate at any adjustable phase angle.

The core technology of the VFT is a rotary transformer with three-phase windings in both the rotor and stator sides. Power flow is proportional to the magnitude and direction of the torque applied to the rotor. This torque is applied to the rotor by a drive motor, which is controlled by a variable-speed drive system. If torque is applied in one direction, then power flows from the stator windings to the rotor windings. If torque is applied in the opposite direction, then power flows from the rotor windings to the stator windings. If no torque is applied, then no real power flows through the rotor transformer.

A closed-loop power regulator maintains power transfer according to the operator set point. The regulator compares measured power with the set point and adjusts motor torque as a function of power error. The power regulator will respond quickly to network disturbances and maintain stable power transfer.[57]

Regardless of power flow, the rotor inherently orients itself to follow the phase angle imposed by the two asynchronous systems, and will rotate continuously if the grids are at different frequencies. The motor and drive system are designed to continuously produce torque while at a standstill. If the power grid on one side experiences a disturbance that causes a frequency excursion, the VFT will rotate at a speed proportional to the difference in frequency between the two power grids. During such a disturbance, if the VFT is transferring power, it will continue without interruption and at full-expected power. The VFT is designed to continuously regulate power flow with drifting frequencies on both grids. Unlike power-electronic alternatives, the VFT produces no harmonics and cannot cause undesirable interactions with neighboring generators or other equipment on the grid.[58]

VFT control system utilizes GE PowerLink Advantage™ HMI PC's provide for superior user interface & monitoring, multi-level dispatch, ramp rate setting and sequence of events recording. The main control cabinet is based on GE D2000 substation automation platform for multi-unit functions, SCDA interface for unmanned operation and data concentration for individual protective devices and units. Individual unit control cabinet, for each 100 MW unit utilizes GE Fanuc PLCs, GE's Multilin Universal Relays, and GE's Turbine Static Starter Control for the fast power and torque regulators.

The first VFT completed commission testing at TransEnergie, Hydro Quebec's Langlois Substation in Quebec, Canada as reported in the October 2004 Transmission and Distribution World. With the VFT in service Hydro-Quebec expects to transfer an extra 100 MW of power between grids. The VFT's 100 MW units can be combined for up to 400 MW in a single installation.[59]

2.4. Conclusion – Phase Shifters

PSTs and VFTs appear to be valuable pieces of equipment to help control the real power flow on AC transmission lines and facilities, and in the case of the VFT the transfer of power from one interconnection to another (e.g. Eastern Interconnection to the Western Interconnection). Having the ability to control power flows is essential if a new line is going to be integrated into

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57. Transmission & Distribution, August 1, 2006 "United States and Mexico Cross-Border Connection" by Rob O'Keefe and David Kidd, American Electric Power page 1

58. GE Energy, Variable Frequency Transformers –

Grid inter-tie, www.ge-energy.com/prod_serv/products/transformers_vft/en/downloads/vft_brochure.pdf

59. Transmission & Distribution World, October 1, 2004 "First VFT System in Service for TransEnergie, aUnit of Hydro-Quebec, http://license.icopyright.net/user/tag.act?tag=3.5531%3ficx_id=tdworld.com/mag/power_united_states_mexico/index.html

the existing AC network, as it would provide some form of protection of the rights of the line owner(s).

One major advantage of the VFT over PSTs is the absence of the tap changer, which historically has caused maintenance issues and prevented the owner from achieving the maximum benefits. The limiting factor of the VFT is the 400 MW limitation at each installation. The two installations that will be using the VFT will be operating at 120 kV and 138 kV. Information for units for higher voltages have not been found as of now.

3.0 Multiple Phase Transmission Line

The use of more than three phases for electric power transmission has been studied for many years. Using six or even 12 phases allows for greater power transfer capabilities within a particular right of way, and reduced EMF's because of greater phase cancellation. The technical challenge is the cost and complexity of integrating such high-phase order lines into the existing three-phase grid.

3.1. Six and 12 Phase Transmission Lines

In the mid-1960's it was observed that rather than going to higher voltage, the number of phases could be increased from three to six, twelve, or more, each step reducing impedance but requiring no more transmission cross section area.

In the late 1970's both six and twelve phase lines were built, tested, and shown to work as predicted. Other theoretical work was done on compact line and the idea of suspending a circuit as though it were insulated conductor bundle. It could, with the aid of ACCR, allow some low voltage single circuit towers to carry three separate circuits.

A less dramatic but quite practical idea, now in use both in Russia and Brazil, greatly expands mid span intra-bundle spacing thereby achieving very low reactance and higher than normal reactive power generation.[60]

This is new technology and still in the development stage. With the advancement of this technology we will find several advantages. Research has been conducted in high phase order (HPO) power transmission where in 6 or 12 phases are used to transmit power in less physical space and with reduced environmental effects than conventional design.

If a three-phase circuit is replaced by a six phase circuit using the same conductor wire diameter and material and operated at the same phase to neutral voltage, then for the same total power transfer (MW), the six-phase conductors will carry only one-half the current of a three-phase conductor line. Also, since the power loss is I^2R, the loss per conductor in the six-phase circuit will be ¼ of that of the three-phase circuit, however, there will be twice as many conductors, so the total line loss will be half of that of the corresponding three-phase line.[61]

3.2. Conclusion – Multiple-Phase Transmission Line

Even though this new technology has promise it is still in its developmental stage and not marketable on a wide scale. AC line configuration using multiple phases may in the future be a viable solution to transmitting large quantities of power, but it will need additional work.

60. http://www.ece.cmu.edu/~electriconf/old2004/Barthold_The%20Future%20of%20Transmission%20Technology.pdf

61. http://www.patentstorm.us/patents/5070441-description.html

4.0 Flexible AC Transmission Systems (FACTS)

Flexible Alternating Current Transmission System (FACTS) is a class of static equipment used to enhanced controllability and increase the power transfer capability of AC transmission of electrical energy. The FACTS devices are generally power electronics-based devices used for the dynamic control of voltage, impedance and phase angle of voltage AC transmission lines. The FACTS equipment can be connected in series with the power system (series compensation), in shunt with the power system (shunt compensation), or both in series and in shunt with the power system.

FACTS is defined by the IEEE as "a power electronic based system and other static equipment that provides control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability."

4.1. Series Compensation

Electrical transmission lines, in addition to conductor resistance, also contain series inductance and shunt capacitance. The series inductance of a long transmission line, operated at high load levels, will cause two things, 1) a significant voltage drop at the receiving end of the line and 2) a phase angle increase between the source and receiving ends that may cause stability issues. Series capacitors are utilized on these long transmission lines to mitigate the negative impacts of inductive reactance and in effect, the series capacitors shorten the line electrically (as much as 70%) and allow for a greater power transfer levels.

Today, Thyristor Controlled Series Compensators (TCSCs) are an extension of conventional series capacitors through adding a thyristor-controlled reactor. Placing a controlled reactor in parallel with a series capacitor enables a continuous and rapidly variable series compensation system. The main benefits of TCSCs are increased energy transfer, dampening of power oscillations, dampening of sub synchronous resonances and control of line power flow. This is a large improvement over the static synchronous series where metal oxide varistors (MOV).

4.2. Shunt Compensation

FACTS devices can provide shunt compensation to the power system, working as a controllable current sources. Shunt compensation is of two types; shunt capacitive compensation and shunt inductive compensation.

- Shunt capacitive compensation is used to improve the power factor on the transmission line. Wherever an inductive load is connected to the transmission line, power factor lags because of lagging load current. To compensate for this power factor lag shunt capacitance is connected to the transmission system, which draws current leading the source voltage and the net result is an improvement in power factor.
- Shunt inductive compensation is connected across the transmission line to prevent, under some conditions, the receiving end voltage from becoming double the sending end voltage. The device will limit high open end voltage when energizing a long

transmission line or high voltage conditions at the receiving end of a long transmission line, during periods light line loading.

4.2.1. Static Var Compensators (SVC's)

These most important FACTS devices have been used for a number of years to improve transmission line economics by resolving dynamic voltage problems. The accuracy, availability and fast response enable SVCs' to provide high performance steady state and transient voltage control compared with classical shunt compensation. SVC's are also used to dampen power swings, improve transient stability, and reduce system losses by optimized relative power control.

4.2.2. STATCOMS

STATCOMS are GTO (gate turn-off type thyristor) based on SVC technology. Compared with conventional SVC's they don't require large inductive and capacitive components to provide inductive or capacitive reactive power to high voltage transmission systems. This results in smaller land requirements. An additional advantage is higher reactive output similar to a synchronous condenser. Thus STATCOMs are able to provide dynamic voltage support to the power system at the bus to which they are connected. The mitigation of voltage instability and system transient stability issues are improved with the use of STATCOMs.

4.2.3. Unified Power Flow Controller (UPFC)

These devices are connected with a STATCOM, which is a shunt connected device, with a series branch in the transmission line via its DC circuit results in a UPFC. This device is comparable to a phase shifting transformer. This solid state device has the advantage of correcting low voltage, reducing overloads by adjusting the series line reactance and changing the phase angle. The UPFC allows for faster network control and better load dynamics on the transmission system.

4.3. Smart Grid

This concept involves utilizing distributed control and monitoring devices to monitor grid status and adjust path flows through flow control devices or generation redispatch. In some functions, the smart grid utilizes communications to coordinate control actions, while other functions are performed autonomously. The smart grid concepts can be applied to all key elements of the electric grid: generation, transmission, distribution, and end-use customers. With a backbone communications system, overloads on key components of the grid can be managed by readjusting generation, adjusting load, or "tuning" the transmission line impedances to rebalance power flows.

One adaptation of the smart grid concept is the use of adaptive distributed FACTS devices installed on several transmission or distribution lines. Devices such as Distributed FACTS (D-FACTS) can either inject series capacitance to reduce the line impedance, inject series reactance to increase the line impedance, or inject shunt series capacitance to support the grid voltage.

Another adaptation, called Smart Wire, is the use of autonomous distributed current limiting conductor (CLiC) modules to control power flow, increase T&D system capacity, and enhance reliability. These devices (called distributed series impedance modules) can inject a small series impedance into the line as the current in the line increases above a predetermined set-point. With the goal of installing many CLiC modules in each phase of a transmission or distribution line, the current (and power flow) can be tuned to increase the overall grid performance by eliminating the first (and subsequent) thermal line limits by redirecting the power flows. Because these devices operate based solely on the transmission line phase current, they can be distributed and autonomous (requiring no communications system to coordinate their operation). If a communications system is available, CLiC devices that can inject both series inductance or series capacitance can be installed.

CLiC concept implementing devices are currently being developed for testing. Initial development will focus on the lower transmission voltages of 161-230 kV, higher voltage devices may be feasible. Because the CLiC concept relies on rebalancing power flows based on line currents, it is useful only in transmission situations where thermal overloads are the basis for limits. Simulation studies suggest that widespread application of CLiC devices can alleviate line loading and congestion issues on complex transmission grids.

4.4. Conclusion - FACTS

It is highly likely that, all or most of the new long transmission lines that will be built in the WECC will utilize several of these technologies, both at the new facilities and at adjacent existing facilities. Their use will ensure grid reliability by providing dynamic power flow, voltage, and phase angle response during transient conditions. The benefits of utilizing FACTS devices in electrical transmission systems can be summarized as follows:

- Better utilization of existing transmission system assets
- Increased transmission system reliability
- Increased dynamic and transient grid stability
- Reduction of loop flows
- Improved power quality for sensitive industries
- No negative environmental impact

4.4.1. Better utilization of existing transmission system assets

In many countries, increasing the energy transfer capability and controlling the load flow of transmission lines are of vital importance, especially in de-regulated markets, where the generation sources with excess and the sinks (load centers) with the greatest needs can change rapidly, frequently, adding new transmission lines to meet increasing electricity demands is limited by economical and environmental constraints. FACTS devices help to meet these requirements with the existing transmission systems.

4.4.2. Increased transmission system reliability and availability

Transmission system reliability and availability is affected by many different factors. Although FACTS devices cannot prevent faults, they can mitigate the effects of faults and make electricity supply more secure by reducing the number of line trips. For example, a major load rejection results in an over voltage of the line which can lead to a line trip. SVC's or STATCOMS counteract the over voltage and avoid line tripping.

4.4.3. Increased dynamic and transient grid stability

Long transmission lines, interconnected grids, impacts of changing loads and line faults can create instabilities in transmission systems. These can lead to reduced line power flow, loop flows or even to line trips. FACTS devices can stabilize transmission systems under transient conditions, which result in higher energy transfer capability and reduced risk of line trips.

4.4.4. Increased quality of supply for sensitive industries

Modern industries depend upon high quality electricity supply including constant voltage and frequency and no supply interruptions. Voltage dips, frequency variations or the loss of supply can lead to interruptions in manufacturing processes with high resulting economic losses. FACTS devices can help provide the required quality of supply.

4.4.5. No negative Environmental impacts

FACTS devices are environmentally friendly. They contain no hazardous materials and produce no waste or pollutants. FACTS help distribute the electrical energy more economically through better utilization of existing installations thereby reducing the need for additional transmission lines.

5.0 High-Voltage Direct Current

HVDC transmission systems contrast with the more common alternating-current systems as a means for the bulk transmission of electrical power. The modern form of HVDC transmission uses technology developed extensively in the 1930's in Sweden by ASEA. Early commercial installations include the USSR in 1951 between Moscow and Kashira, and a 10-20 MW system in Gotland, Sweden in 1954[62]

5.1. History of HVDC Transmission

An early method of high-voltage DC transmission was developed by the Swiss engineer Rene Thury[63]. This system used series-connected motor-generator sets to increase voltage. Each set was insulated from ground and driven by insulated shafts from a prime mover. The line was operated in constant current mode, with up to 5000 volts on each machine, some machines having double commentators to reduce the voltage on each commutation. An early example of this system was installed in 1889 in Italy by the Society *Acquedotto de Ferrari-Galliera.* This system transmitted 630 kW at 14 kV over a distance of 120 km (approx. 74.5 miles)[64]. Other Thury systems operating at up to 100 kV DC operated up until the 1930's, but the rotation machinery required high maintenance and had high energy loss. Various other electromechanical devices were tested during the first half of the 20th century with little commercial success[65].

The grid controlled mercury arc valve became available for power transmission during the period 1920 to 1940. In 1941 a 60 MW, +/- 200 kV, 115 km buried cable link was designed for the city of Berlin using mercury arc valves (Elbe-Project), but owing to the collapse of the German government in 1945 the project was never completed.[66] The equipment was moved to the Soviet Union and was put into service there.[67]

Introduction of the fully-static mercury arc valve to commercial service in 1954 marked the beginning of the modern era of HVDC transmission. Mercury arc valves were common in systems designed up to 1975, but since then HVDC systems use only solid-state devices.

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62. Narain G. Hingorani in *IEEE Spectrum* magazine, 1996.

63. Donald Beaty et al, "Standard Handbook for Electrical Engineers 11th Ed.", McGraw Hill, 1978

64. http://www.myinsulators.com/acw/bookref/histsyscable/

65. Shaping the Tools of Competitive Power http://www.tema.liu.se/tema-t/sirp/PDF/322_5.pdf

66. http://www.rmst.co.il/HVDC_Proven_Technology.pdf

67. http://www.ieee.org/organizations/history_center/Che2004/DITTMANN.pdf

5.1.1. Advantages of HVDC over AC Transmission

In a number of applications the advantages of HVDC makes it the preferred option over AC Transmission.

- Underwater cables, where high capacitance causes additional losses.
- Terminal to terminal long distance bulk power transmission.
- Power transmission between unsynchronized AC systems.
- Reduced profile of towers and lines for bulk power transmission.
- Termination at remote generating facilities
- Stabilizing AC power-grid, by being isolated from loop flow.
- Reducing Corona discharge as compared to HVAC transmission lines of similar capacity.
- Reducing line cost since HVDC transmission requires fewer conductors (i.e. 2 conductors).

In general, a HVDC power line will interconnect two or more AC systems. Equipment to convert between AC and DC power can add a considerable cost in power transmission. The conversion from AC to DC is known as rectification and from DC to AC as inversion. Above a certain break-even distance about 30 miles for submarine cables, and approximately 400-500 miles for overhead lines.[68]

The conversion electronics also present an opportunity to effectively manage the power grid by means of controlling the magnitude and direction of power flow. An additional advantage of the existence of HVDC links, therefore, is potential increased stability in the transmission grid.

HVDC can carry more power per conductor, because for a given power rating the constant voltage of a DC line is lower then the peak voltage in an AC line. This voltage determines the insulation required and conductor spacing. This allows existing transmission line corridors to be used to carry more power into an area of high power consumption, which can lower costs.

HVDC allows bulk power transmission between two asynchronous AC systems, thereby improving system stability by preventing cascading failures from propagating from one part of a wider power transmission grid to another, whilst still allowing power to be imported or exported in the event of an AC failure. This has caused many power systems to contemplate wider use of HVDC technology for its stability benefits alone.

5.1.2. Hybrid HVDC and AC

The combination of HVDC and AC is an option for bulk power on a long line with multiple participants. In this option the first segment of the transmission line would be HVDC and at the receiving end it would be integrated with the AC grid and be utilized to move the energy to the different load centers.

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68. http://en.wikipedia.org/wiki/HVDC

5.1.3. Disadvantages of HVDC

The required static converters (rectifiers and inverters) are expensive and cannot withstand significant overloads. At shorter transmission distances the losses in the static converters may be higher than in an AC power line, and the cost of the converters may not be offset by reductions in line construction cost. Recent economic assessments suggest that for deliveries of 3,000 MW of capacity, HVDC is economical compared to 500 kV AC when the delivery distance exceeds 400 to 500 miles.

In contrast to AC systems, realizing multiterminal systems is complex, as is expanding existing schemes to multiterminal systems. Controlling power flow in a multiterminal DC system requires good communication between all the terminals: power flow must be actively regulated by the control system instead of the inherent properties of the transmission line.

5.1.4. Back to Back HVDC Terminals

A back to back station is a HVDC plant in which both converters are in the same area, usually in the same building. The length of the DC line is only a few feet. These back to back DC stations are used for:

- Coupling of electricity systems of different frequency
- Coupling two systems of the same nominal frequency giving isolation to the AC systems.

The DC voltage in the intermediate circuit can be selected freely at HVDC back-to-back stations because of the short conductor length. The DC voltage is as low as possible, in order to build a small valve hall and avoid parallel switching of valves. For this reason at HVDC back to back stations valves with the highest current rating are used.

5.1.5. System with DC Transmission Lines

The most common configuration of an HVDC link is a station-to-station link, where two inverter/rectifier converter stations are connected by means of a dedicated HVDC link. This is also a configuration commonly used in connecting unsynchronized grids, in long-haul power transmission and in undersea cables.

Multi-terminal HVDC links, connecting more than two points, are rare. The configuration of multiple terminals can be series, parallel, or a mixture of series and parallel. Parallel configuration tends to be used for large capacity stations, and series for lower capacity stations. An example is the 2000 MW Quebec-New England transmission system commissioned as the first large multi-terminal facility in 1992[69].

The Garabi station power rating is a 2,200 MW configuration. The AC transmission systems in Brazil and Argentina consist of a 500 kV network. The DC voltage between the two valve groups is +/- 70 kV. The main reason for choosing HVDC is the fact that Argentina operates at

69. ABB HVDC Transmission Québec - New England

50 cycles and Brazil at 60 cycles. The control system utilizes ABB's Capacitor Commutated Converters (CCC). The first phase was placed in service in 2000 and the second in 2002.

The chart below shows the cost broken down for line, station and losses for both AC voltages and DC voltage options.[70]

6.0 Extra-high Voltage Transmission Lines

The four popular transmission AC voltages used in the United States is 230, kV, 345 kV, 500 kV and 765 kV. The WECC utilizes 500, 345 and 230 kV as the primary voltages for shipping large quantities of power. This technology is well established. The use of 765 kV extra-high AC transmission voltage has enhanced the Eastern Interconnection's ability to move massive amounts of energy from source to customer. With the 765 kV transmission lines, several times the power of lower voltage lines can be transmitted over long distances with only 200 feet of right of way.

Transmission at 765 kV also offers greater reliability due to its line design. With only one line outage per 100-mile year, 765 kV reliability surpasses all other voltage classes.[71] In addition, 765 kV faults are usually momentary and involve only one of three phases, allowing application of single-phase tripping.

Station equipment for 765 kV has matured and transformer bank sizes up to 3,000 MVA have been demonstrated throughout the world. The necessity of using banks of single-phase transformers allows spare units to be used easily achieved with a fourth single-phase transformer connectable to any phase without physical moves, reducing outage duration.

A 765 kV system is an alternating current (AC) transmission, which lends itself to ready integration with existing and future infrastructure. Direct current (DC) transmission is also useful over long distances, but cannot be integrated well without significant cost.

Assuming the need to transport 3,000 MW, one 765 kV line with six bundled conductors per phase would be required. Using 500 kV would require two circuits, each carrying 910 MW, and six 345 kV lines would be required. The Eastern Interconnection is utilizing 765 kV transmission lines and have found that the cost per mile is acceptable for their systems. This is not true for the Western Interconnection, since there is no 765 kV infrastructure is this region. A recent study conducted by the participants of the TransWest Express Transmission Project evaluated the costs of several transmission alternatives related to a 3,000 MW transmission system (AC vs DC) from the Wyoming Region to the Desert Southwest Region. The cost of a two line 500 kV system was approximately $4.5 billion, the cost of a two line 765 kV system was approximately

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70..http://www02.abb.com/global/seitp/seitp202.nsf/0/5392089edc1b3440c12572250047fd78/$file/800+kV+DC+technology.pdf

71. Electric Light and Power, Jan 2007 – The Next Interstate System: 765 kV Transmission

$5.3 billion and the cost for a single bi-polar DC line was approximately $2.3 billion. Note: the cost for the 765 kV option is higher, due to additional infrastructure requirements (e.g. transformers), but the facilities could ultimately be utilized to transfer up to 5,000 MW.

Appendix A of Appendix D

Table APD-1. HVDC Systems that use (or used) mercury arc rectifiers

Name	Converter Station 1	Converter Station 2	Length of Cable	Length of overhead line	Voltage	Transmission power	Inauguration	Remarks
Elbe-Project	Dessau, Germany	Berlin-Marienfelde, Germany	100 km/ 62 miles	-	+/- 200 kV	60 MW	1945	Never placed in service, dismantled
Moscow-Kashira	Moscow, Russia	Kashira, Russia	100 km/ 62 miles	-	200 kV	30 MW	1951	Built parts of HVDC Elbe-Project
Gotland 1	Vaestervik, Sweden	Ygne, Sweden	98 km/ 61 miles	-	200 kV	20 MW	1954	Shut down 2/86
HVDC Cross-Channel	Echingen, France	Lydd, UK	64 km/ 40 miles	-	+/- 100 kV	160 MW	1961	Shut down in 1984
Konti-Skan 1	Vester Hassing, Denmark	Stenkullen, Sweden	87 km/ 54 miles	89 km/ 55 miles	250 kV	250 MW	1964	Replaced in 8/06 with Thyristors
HVDC Volgograd-Donbass	Volzhskaya, Russia	Mikhailovskaya, Russia	_	475 km/ 295 miles	+/- 400 kV	750 MW	1964	

Name	Converter Station 1	Converter Station 2	Length of Cable	Length of overhead line	Voltage	Transmission power	Inauguration	Remarks
HVDC Inter-Island	Benmore Dam, New Zealand	Haywards, New Zealand	40 km/ 25 miles	570 km/ 354 miles	+270 kV -350 kV	1200 MW	1965	Upgraded in 1991. Pole 1 is still Mercury Arc. Pole 2 is Thyristors
HVDC back to back station Sakuma	Sakkuma, Japan	Sakuma, Japan	-	-	+/- 125 kV	300 MW	1965	Replaced in 1993 with Thyristors
SACOI 1	Suvereto, Italia	Lucciana, Corse: Codrongianos, Sardinia	304 km/ 189 miles	118 km/ 73 miles	200 kV	200 MW	1965	Replaced in 1986 with Thyristors
HVDC Vancouver Island 1	Delta, British Columbia	North Cowican, British Columbia	42 km/ 26 miles	33 km/ 21 miles	260 kV	312 MW	1968	
Pacific interties	Celilo, Oregon	Sylmar, California	-	1362 km/ 846 miles	+/- 500 kV	3100 MW	1970	Mercury arc valves replaced in 2004
Nelson River Bipole 1	Gillalm, Canada	Rosser, Manitoba	-	895 km/ 556 miles	+/- 450 kV	1820 MW	1971	Converted to Thyristors 1993, 2004

Name	Converter Station 1	Converter Station 2	Length of Cable	Length of overhead line	Voltage	Transmission power	Inauguration
HVDC Kingsnorth	Kingsnorth, UK	Lindon-Beddington, UK: London-Willesden, UK	85 km/ 53 miles	-	+/- 266 kV	640 MW	1975

Table APD-2. Systems that used Thyristors from first power-on

Name	Converter Station 1	Converter Station 2	Length of Cable	Length of overhead line	Voltage	Transmission power	Inauguration
HVDC back to back station Eel River	New Brunswick, Canada	New Brunswick, Canada	-	-	80 kV	320 MW	1972
Cross-Skagerrak 1&2	Tjele, Denmark	Kristiansand, Norway	30 km/ 64 miles	100 km/ 62 miles	+/- 250 kV	1000 MW	1977
HVDC Vancouver, Island 2	Delta, British Columbia	North Cowichan, British Columbia	33 km/ 21 miles	42 km/ 26 miles	280 kV	370 MW	1977
Square Butte	Center, North Dakota	Arrowhead, Minnesota	-	749 km/ 465 miles	+/- 250 kV	500 MW	1977

Name	Converter Station 1	Converter Station 2	Length of Cable	Length of overhead line	Voltage	Transmission power	Inauguration
HVDC back to back, Shin Shinano	Shin, Shinano, Japan	Shin, Shinano, Japan	-	-	+/- 250 kV	600 MW	1977
CU	Coal Creek, North Dakota	Dickinson, Minnesota	_	710 km/ 441 miles	+/- 400 kV	1000 MW	1979
HVDC Hokkaido-Honshu	Hakodate, Japan	Kamikita, Japan	44 km/ 27 miles	149 km/ 93 miles	250 kV	300 MW	1979
Cabora Bassa	Songo, Mozambique	Apollo, South Africa	-	1420 km/ 882 miles	+/- 533 kV	1920 MW	1979
Inga-Shaba	Kolwezi, Zaire	Inga, Zaire	-	1700 km/ 1056 miles	+/- 500 kV	560 MW	1964
HVDC back to back Acaray	Acaray, Paraguay	Acaray, Paraguay	_	_	25.6 kV	50 MW	1981
HVDC back to back Vyborg	Vyborg, Russia	Vyborg, Russia	-	-	+/- 85 kV	1065 MW	1982
HVDC back to back Durnrohr	Dunrohr, Austria	Dunrohr, Austria	_	_	145 kV	550 MW	1983
HVDC Gotland 2	Vastervik, Sweden	Yigne, Sweden	92.9 km/ 58 miles	6.6 km/ 4 miles	150 kV	130 MW	1983

Name	Converter Station 1	Converter Station 2	Length of Cable	Length of overhead line	Voltage	Transmission power	Inauguration
HVDC back to back Artesia, New Mexico	Artesia, New Mexico	Artesia, New Mexico	-	-	82 kV	200 MW	1983
HVDC back to back Chateauguay	Chateauguay Saint-Constant	Chateauguay Saint-Constant	-	-	140 kV	1000 MW	1984
HVDC Itaipu 1	Foz do Iguacu, Parana	Sao Roque, Sao Paulo	_	785 km/ 488 miles	+/- 600 kV	3150 MW	1984
HVDC Itaipu 2	Foz do Iguacu, Parana	Sao Roque, Sao Paulo	-	805 km/ 500 miles	+/- 600 kV	3150 MW	1984
HVDC back to back Oklaunion	Oklaunion	Oklaunion	-	-	82 kV	200 MW	1984
HVDC back to back Blackwater, New Mexico	Blackwater, New Mexico	Blackwater, New Mexico	_	_	57 kV	200 MW	1984
HVDC back to back Highgate, Vermont	Highgate, Vermont	Highgate, Vermont	-	-	56 kV	200 MW	1985
HVDC back to back Madawaska	Madawaska	Madawaska	_	_	140 kV	350 MW	1985

Name	Converter Station 1	Converter Station 2	Length of Cable	Length of overhead line	Voltage	Transmission power	Inauguration
HVDC back to back Miles City	Miles City	Miles City	_	_	+/- 82 kV	200 MW	1985
Nelson River Bipole 2	Sundance, Canada	Rosser, Canada	-	937 km/ 582 miles	+/- 500 kV	1800 MW	1985
HVDC Cross-Channel	Les Mandarins, France	Sellingge, UK	72 km/ 45 miles	-	+/- 270 kV	2000 MW	1986
HVDC back to back Broken Hill	Broken Hill	Broken Hill	-	-	+/- 8.33 kV	40 MW	1986
Intermountain	Intermountain	Adelanto, California	-	785 km/ 488 miles	+/- 500 kV	1920 MW	1986
HVDC back to back Uruguaiana	Uruguaiana, Brazil	Uruguaiana, Brazil	-	-	+/- 17.9 kV	53.9 MW	1986
HVDC Gotland 3	Vastervik, Sweden	Yigne, Sweden	98 km/ 61 miles	-	150 kV	130 MW	1987
HVDC back to back Virgina Smith	Sidney, Nebraska	Sidney, Nebraska	-	-	55.5 kV	200 MW	1988
Konti-Skan 2	Vester Hassing, Denmark	Stenkullen, Sweden	87 km/ 54 miles	60 km/ 37 miles	285 kV	300 MW	1988

Name	Converter Station 1	Converter Station 2	Length of Cable	Length of overhead line	Voltage	Transmission power	Inauguration
HVDC back to backMc Neill	Mc Neill, Canada	Mc Neill, Canada	-	-	42 kV	150 MW	1989
HVDC back to back Vindhyachal	Vindhyachal, India	Vindhyachal, India	-	-	176 kV	500 MW	1989
HVDC Sileru-Barsoor	Sileru, India	Barsoor, India	-	196 km/ 122 miles	+/- 200 kV	400 MW	1989
Fenno-Skan	Dannebo, Sweden	Rauma, Finland	200 km/ 124 miles	33 km/ 21 miles	400 kV	500 MW	1989
HVDC Gezhouba-Shanghai	Gezhouba, China	Nan Qiao, China	-	1046 km/ 650 miles	+/- 500 kV	1200 MW	1989
Quebec-New England	Radisson, Quebec	Nicolet, Quebec: Des Cantons, Quebec; Comerford, New Hampshire;James Bay, Mass.	-	1100 km/ 684 miles	+/- 450 kV	2000 MW	1991
HVDC Rihand-Delhi	Rihand, India	Dadri, India	-	814 km/ 506 miles	+/- 500 kV	1500 MW	1992

Name	Converter Station 1	Converter Station 2	Length of Cable	Length of overhead line	Voltage	Transmission power	Inauguration
SACOI 2	Suvereto, India	Lucciana, France Codrongianos, Italy	118 km/ 73 miles	304 km/ 189 miles	200 kV	300 MW	1992
HVDC Inter-Island 2	Benmore Dam, New Zealand	Haywards, New Zealand	40 km/ 25 miles	570 km/ 354 miles	350 kV	640 MW	1992
Cross-Skagerrak 3	Tjele, Denmark	Kristiansand, Norway	130 km/ 81 miles	100 km/ 62 miles	350 kV	500 MW	1993
Baltic-Cable	Lubeck-Herrenwyk, Germany	Kruseber, Sweden	250 km/ 155 miles	12 km/ 7 miles	450 kV	600 MW	1993
HVDC back to back Etzenricht	Etzenricht, Germany	Etzenricht, Germany	-	-	160 kV	600 MW	1993
HVDC back to backVienna-Southeast	Vienna, Austria	Vienna, Austria	-	-	142 kV	600 MW	1993
HVDC Haenam-Cheju	Haenam, South Korea	Jeju, South Korea	101 km/ 63 miles	-	180 kV	300 MW	1996
Kontek	Bentwisch, Germany	Bjaeeverskov, Denmark	170 km/ 106 miles	-	400 kV	600 MW	1996

Name	Converter Station 1	Converter Station 2	Length of Cable	Length of overhead line	Voltage	Transmission power	Inauguration
HVDC Hellsjon-Grangesberg	Hellsjoen, Sweden	Graengesberg, Sweden	-	10 km/ 6 miles	180 kV	3 MW	1997
HVDC back to back Wesch-Monticello	Welch-Monticello, Texas	Welch-Monticello, Texas	-	-	162 kV	600 MW	1998
HVDC Leye-Luzon	Orno, Leyton	Ormoc, Luzon	21 km/ 13 miles	430 km/ 267 miles	350 kV	440 MW	1998
HVDC Visby-Nas	Nas, Sweden	Visby, Sweden	70 km/ 43 miles	-	80 kV	50 MW	1999
Swepol	Starno, Sweden	Slupsk, Poland	245 km/ 152 miles	-	450 kV	600 MW	2000
HVDC Italy-Greece	Galatina, Italy	Arachthos, Greece	200 km/ 124 miles	110 km/ 68 miles	400 kV	500 MW	2001
Kii Channel HVDC	Anan, Japan	Kihoku, Japan	50 km/ 31 miles	50 km/ 31 miles	+/- 500 kV	1400 MW	2000
HVDC Moyle	Auchencrosh, UK	Ballycronan More, UK	63.5 km/ 39 miles	-	250 kV	250 MW	2001
HVDC Thailand-Malaysia	Khlong Ngae, Thailand	Gurun, Malaysia	-	110 km/ 68 miles	300 kV	300 MW	2002

Name	Converter Station 1	Converter Station 2	Length of Cable	Length of overhead line	Voltage	Transmission power	Inauguration
HVDC back to back Minami-Fukumitsu	Minami-Fukumitsu, Japan	Minami-Fukumitsu, Japan	-	-	125 kV	300 MW	1999
HVDC three Gorges-Changzhou	Longquan, China	Zhengping, China	-	890 km/ 553 miles	+/- 500 kV	3000 MW	2003
HVDC Gorges-Guangdong	Jingzhou, China	Huizhou, China	-	940 km/ 584 miles	+/- 500 kV	3000 MW	2003
Basslink	Loy Yang, Australia	George Town, Australia	298 km/ 185 miles	72 km/ 45 miles	400 kV	600 MW	2005
Vizag II	Gazuwaka, India	Gazuwaka, India	-	-	176 kV	500 MW	2005
HVDC back to back Sharyland	Sharyland, Texas	Shareyland, Texas	-	-	+/- 21 kV	150 MW	2007
Imera Power HVDC Wales-Ireland, East West Interconnector	Leinster, Ireland	Anglesea, Wales	130 km/ 81 miles	-	+/- 400 kV	500 MW	2008
SAPEI	Latina, Italy	Fiume Santo, Sardinia	435 km/ 270 miles	-	+/- 500 kV	1000 MW	2008/9

Name	Converter Station 1	Converter Station 2	Length of Cable	Voltage	Transmission power	Inauguration
NorNed	Feda, Norway	Eemshaven, Netherlands	580 km/ 360 miles	+/- 450 kV	700 MW	2010
HVDC back to back Vishakapatinam	Vishakapatinam, India	Vishakapatinam, India	-			

Table APD-3. Systems that used IBTs

Name	Converter Station 1	Converter Station 2	Length of Cable	Length of overhead line	Voltage	Transmission power	Inauguration	Remarks
HVDC Tjaereborg	Tjaereborg, Denmark	Tjaereborg, Denmark	4.3 km/ 3 miles	-	+/- 9 kV	7.2 MW	2000	Wind Power
HVDC back to back Eagle Pass, Texas	Eagle Pass, Texas	Eagle Pass, Texas	-	-	+/- 15.9 kV	36 MW	2000	
Directlink	Mullumbimby, Australia	Bungalora, Australia	59 km/ 37 miles	-	+/- 80 kV	180 MW	2000	Land Cable
Cross Sound Cable	New Haven, Connecticut	Shoreham, Long Island	40 km/ 25 miles	-	+/- 150 kV	330 MW	2002	Underwater cable
Murraylink	Berri, Australia	Red Cliff, Australia	177 km/ 110 miles	-	+/- 150 kV	220 MW	2002	Land CableHVDC
HVDC Troll	Kolsnes, Norway	Offshore platform Troll A	70 km/ 43 miles	-	+/- 60 kV	84 MW	2005	Power for offshore gas compressor
Estlink	Espoo, Finland	Harku, Estonia	105 km/ 65 miles	-	+/- 150 kV	350 MW	2006	

HVDC Valhall	Lista, Norway	Valhall, Offshore platform	292 km/ 181 miles	-	150 kV	78 MW	2009	

Appendix E

Alternative Approaches Utilized for Transmission Project Approvals—Transmission Planning and Review of Industry and Regulatory Changes

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Abstract

California's electric industry went through a growth spurt in the 1950's, 60's, and early 70's. Many of the major transmission interconnection projects were built, planned, or conceived during this time period. These projects were planned and built by vertically integrated utilities with the primary purpose of connecting new generation or accessing new or surplus energy and capacity.

The picture today is much different. Open access transmission rules separate ownership of transmission from rights to transmission. Transmission planning has shifted to California Independent System Operator for at least the investor-owned utilities. It is no longer possible for utilities to simply plan new transmission and expect cost recovery.

This research effort has focused on the changes that have taken place within the electric industry over the past five decades in an effort to better understanding their impacts on the transmission planning process. The key impacts on the transmission planning process:

1. The traditional utility planning process transitioned from vertically integrated to disaggregated planning for transmission and generation.
2. Utility-led to ISO-led transmission planning with stakeholder participation.
3. Utility footprint planning to regional planning with stakeholder participation.
4. Utility transmission usage rights to open access policy.
5. Separation between the generation and transmission functions—no information sharing or planning coordination.

Keywords: Electric industry changes, regulatory change, transmission planning process, California electric industry, evolving market in California, CA ISO, transmission

Executive Summary

California's electric industry went through a growth spurt in the 1950's, 60's, and early 70's. Many of the major transmission interconnection projects were built, planned, or conceived during this time period. These include for example, transmission into California from:

- Four Corners Power Plant, New Mexico.
- Navajo Power Plant, Arizona.
- Palo Verde Nuclear Plant, Arizona.
- Southwest Power Link, Arizona.
- Mohave Power Plant, Nevada.
- Pacific Intertie, Pacific Northwest.
- Intermountain Power Plant, Utah.
- Federal Electricity Commission's (CFE's) Cerro Prieto Plant, Baja Mexico.

All these projects were planned and built by vertically integrated utilities with the primary purpose of connecting new generation or accessing new or surplus energy and capacity. Projects were rate-based; customers paid for transmission as part of the bundled rate; and customers enjoyed the benefits of ownership through exclusive or primary rights to use the transmission system.

The picture today is much different. Open access transmission rules separate ownership of transmission from rights to transmission. Utilities are no longer integrated—generation and transmission functions are separated. Transmission planning has shifted from the utilities to California Independent System Operator (CA ISO) for at least the investor-owned utilities. In many cases an Independent Power Producer (IPP) is the project sponsor for new power plants and, in some instances, an Independent Transmission Company (ITC) will sponsor a new transmission line (e.g. Path 15 upgrade).

These changes are the culmination of 50-years of changes in the electric industry—regulatory, legislative, and structural. California's electric industry evolution in terms of time period, policy issues, and transmission planning changes are described throughout the various sections of this report. These evolutionary changes in the electric industry have had a significant impact on planning for new transmission, cost allocation, and cost recovery. It is no longer possible for utilities to simply plan new transmission and expect cost recovery. The consequences of these changes can be summarized as follows:

Pre 80's	▪ Major new utility planned transmission primarily to connect new generation or access surplus energy or capacity. ▪ Project planned by vertically integrated utilities based on long term (20-years or longer) resource plans.
80's & 90's	▪ Few transmission interconnections built due to capacity surpluses, environmental opposition, regulatory uncertainties, industry restructuring, and changing

	transmission business landscape due to advent of open access and non utility generation.
Post California Energy Crisis in 2001	▪ New transmission planning processes start to take shape. ▪ Transmission planning more open and collaborative with heavy stakeholder involvement. ▪ Planning focus shifted from utilities to CA ISO ▪ Projects starting to be approved. ▪ Issues regarding project sponsorship, analysis methodologies, cost recovery evolving.

Research Findings and Conclusions:

This research effort has focused on the changes that have taken place within the electric industry over the past five decades in an effort to better understanding their impacts on the transmission planning process. The key findings from the research are that industry changes have impacted the transmission planning process in the following five key areas:

1. The traditional utility planning process transitioned from vertically integrated to disaggregated planning for transmission and generation.
2. Utility led to ISO led transmission planning with stakeholder participation.
3. Utility footprint planning to regional planning with stakeholder participation.
4. Utility transmission usage rights to open access policy.
5. Separation between the generation and transmission functions—no information sharing or planning coordination, making transmission planning more difficult.

The following sections of this report are a historical review of the California Electric Power Industry and the changes it underwent over the past five decades.

1.0 Background

This project was commissioned to provide research and background information for a research project on the broader topic of *Benefit Quantification and Cost Allocation*. As part of the Benefit Quantification and Cost Allocation Research Project, the research team performed a scoping study to understand transmission benefit quantification, cost allocation, cost recovery, and project approval processes with a particular focus on recommending new methods for improved benefit quantification and cost allocation that better fits the new electric industry structure and planning environment. There were many key policy questions that came up as part of this broader research, for example impact of transmission technologies, lessons learnt from other regions and industries and the subject of this report *impacts of industry and regulatory changes*.

2.0 Introduction

As indicated above, this research project was used to provide information to the broader subject of *Benefit Quantification and Cost Allocation*. As part of that project it was determined that, for the most part, utility efforts to develop new transmission projects that are local in nature, address well documented reliability needs, are required for interconnecting new load or generation are generally supported and have been gaining regulatory approvals and stakeholder support. However, major regional transmission projects that involve multiple jurisdictions and utilities and are needed for integrating remote resources, reducing costs, improving market operations, providing long term strategic benefits and improving operating flexibility, don't have a clear path forward….. Why? In an attempt to help answer this question, the project team was asked to research the electric industry and regulatory changes that occurred over the past five decades and determine the impacts they had on the transmission planning process.

The following section of this report covers the time span from the 1950's through 2005+ and provides a non-technical summary of the industry changes that were occurring each decade, changes or shifts in the state and federal regulatory process, and a recap of the utility and regional transmission planning process during each decade.

3.0 Project Approach

The research approach used for this project included the following components:

- Information Collection
  - Compiled data from various industry web sites.
  - Reviewed and processed data for pertinent information and time lines.
- Conducted interview with Electric Power Group Team members and other industry leaders with first-hand knowledge of industry changes and planning processes.

Produce report of research findings.

4.0 History Of The California Electric Power Industry—Time Periods, Issues, And Transmission Planning

4.1. Golden Era – The 50's and 60's

Figure APE- 1. Golden Era—The 50's and 60's

The era following the end of World War II, due to the development of the defense industry on the west coast and job opportunities for the returning troops, marked a time of tremendous prosperity for the electric utility industry. The demand for electric energy grew rapidly, consistently, and predictably, with declining electricity rates. The state's utilities started the transition from somewhat isolated utilities to a fully interconnected region. The utilities were challenged to keep up with the need to construct new power plants and transmission infrastructure to meet growing electricity needs.

There were several drivers to a healthy and robust electric industry during this time period:

- Electrification—the conversion from gasoline and natural gas use to an expanded use of electric energy to improve industry production and efficiency (e.g., steel mills, agricultural irrigation).
- Double digit growth—during the 50's and 60's the population in California doubled from approximately 10 million to 20 million[72] requiring significant utility investment in both power plants and transmission/distribution infrastructure in an effort to keep up with the growing energy demand. Also, the average household started to increase in size (1950 average was 850 square feet[73]) which required more heating and cooling and also bigger and more appliances and equipment.
- Declining Rates—a major contributor to the reduction in electric rates during these two decades was the construction of new and larger fossil fuel power plants that provided significant improvements in plant efficiency. The power plants built prior to the 50's consisted of units that varied in size from 30 to 90 megawatt (MW) and, between the 50's and 60's, the plants consisted of units growing in size from 130 MW to 800 MW. In addition, the plants implemented the use of new technology that included automated controls and computers allowing the conversion from drum type boilers to super-critical boilers for improved efficiency. The heat rates of the new plants were approximately

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72. Public Policy Institute *of* California www.ppic.org

73. Energy Information Administration - http://tonto.eia.doe.gov/FTPROOT/electricity/0562.pdf

10,800 British thermal unit (Btu) per kilowatt-hour[74], almost a 30% improvement over the pre-1950 vintage plants that had a heat rate in excess of 15,000 Btu per kilowatt-hour. This era was also the beginning of nuclear generation in California. In 1968, San Onofre Unit 1 went into operation, the first of six nuclear plants to be built in California.

4.1.1. Regulation and Planning Process for the Investor-Owned Utility (IOU), during the 50's and 60's:

State of California:

- CPUC—The CPUC reviewed and approved generation and transmission projects and established retail rates.

In 1912, the Legislature passed the Public Utilities Act[75], expanding the Railroad Commission's regulatory authority to include natural gas, electric, telephone, and water companies, as well as railroads and marine transportation companies. In 1946, the Commission was renamed the California Public Utilities Commission (CPUC).

Federal:

- Federal Energy Regulatory Commission (formerly FPC) - FERC reviewed and approved hydro plant licensing, wholesale power and transmission service rates.

In 1920, Congress established the Federal Power Commission (FPC)[76] to coordinate hydroelectric projects under federal control. The Federal Power Act of 1935 and the Natural Gas Act of 1938 gave the FPC the power to regulate the sale and transportation of electricity and natural gas.

- Nuclear Regulatory Commission (formerly AEC)[77] - NRC reviewed and approved nuclear plant licensing.

Before the Nuclear Regulatory Commission was created, nuclear regulation was the responsibility of the AEC, which Congress first established in the Atomic Energy Act of 1946. Eight years later, Congress replaced that law with the Atomic Energy Act of 1954, which for the first time made the development of commercial nuclear power possible. The act assigned the AEC the functions of both encouraging the use of nuclear power and regulating its safety. The Energy Reorganization Act of 1974 created the Nuclear Regulatory Commission; it began operations on January 19, 1975.

Transmission Planning:

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74. Derived from Edison Electric Institute, *EEI Pocketbook of Electric Utility Industry Statistics* (1983), p. 21

75. CPUC web site - http://www.cpuc.ca.gov/static/aboutcpuc/puhistory.htm

76. FERC web site - http://www.ferc.gov/students/whatisferc/history.htm

77. NRC web site - http://www.nrc.gov/about-nrc/history.html#aec-to-nrc

- 50's—The transmission planning process consisted of vertically integrated planning and review process with some coordination with adjacent utilities.
- 60's—The transmission planning consisted of vertically integrated planning and review process and extensive coordination and review with sub-regions of the Western Electricity Coordinating Council (e.g. Pacific Northwest and Desert Southwest) and adjacent utilities. During the late 60s, as a result of the 1965 Northeast blackout, the North American and regional reliability councils (NERC/WECC) were in the early formation stages. Several major new transmission lines were built—almost all designed to integrate new generation power plants, including for example, Mohave, Four Corners, and Navajo coal plants.

4.2. Roadblock Years - The 1970's

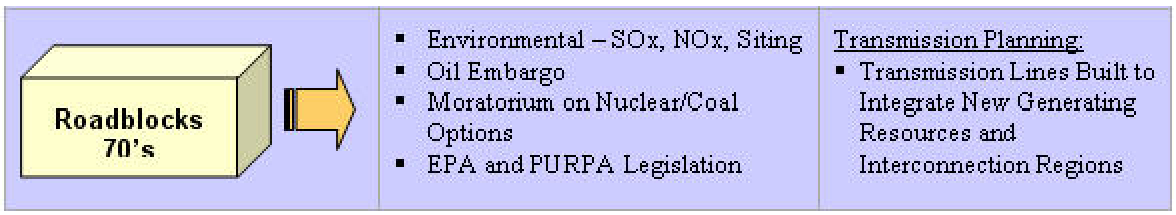

Figure APE- 2. Roadblock Years—The 1970's

In general, the decade of the 1970s was not great for the electric utilities in California. The trend indicated a move from decreasing unit costs and rapid growth to increasing unit costs and slower overall growth. The major driving factors affecting the industry were:

- Environmental concerns.
- Drastic increases in fossil-fuel prices and double digit inflation.
- Conservation.
- Problems in the nuclear power industry after the Three Mile Island event.

4.2.1. Environmental Concerns

By the early 1970's, there was a much greater emphasis being put on the environmental issues and that had a noticeable impact on the electric industry in the form of environmental requirements and electric utility costs, including the cost of building and operating power plants.

The Clean Air Act of 1970 (CAA, P.L. 91-604) and its amendments in 1977 (P.L. 95-95) required utilities to reduce pollutant emissions, particularly SO_2, causing increases in capital, fuel, and operating costs.

- Air Quality and Environmental Impacts—In the early 1970, the primary fuel being burned at generating plants within California was oil. Natural gas was reserved for the gas company's core residential, commercial and industrial customers and was only available to the electric power industry on an interruptible basis. This high dependency on oil and the associated air quality issues required the utilities, with poor air quality in their service territory (e.g., Southern California Edison) to do two things: 1), to implement nitrogen oxides (NOX) dispatch programs for their fossil fuel generation resources as opposed to least cost dispatch; and, 2) procure only low sulfur oil to burn in the boilers.

- The new coal-fired power plants in the Desert Southwest, that the California utilities participated in, were experimenting with emission control equipment to decrease the amount of sulfur dioxide (SO_2) emitted into the atmosphere. In addition, the flue gases were passed through precipitators that removed much of the particulate matter and the gas was sent up tall emission stacks to better disperse the SO_2.
- The National Environmental Policy Act of 1969 (NEPA, P.L. 91-190) required utilities seeking Federal permits for new power plants to prepare and defend environmental impact statements (EIS) as a part of the permit process.

4.2.2. High oil prices and double digit inflation

In the 1970's the cost of imported oil rose sharply. Petroleum costs more than doubled in 1974 alone and increased an average of over 26% a year for the period 1970-1980. Coal price increases averaged almost 16% a year. For the first time in the history of U.S. electric power, electricity prices rose consistently, with nominal price increases averaging 11% a year.[78]

4.2.3. Conservation of Fossil Fuels and Energy Use

During the 70's there were several pieces of federal legislation that impacted both its future fuel sources and energy sales. The conservation legislation effectively barred utilities from future use of natural gas and petroleum. The Energy Supply and Environmental Coordination Act of 1974 (ESECA, P.L. 93-319) allowed the Federal Government to prohibit electric utilities from burning natural gas or petroleum. The 1978 Powerplant and Industrial Fuel Use Act (PIFUA, P.L. 95-620) succeeded ESECA and extended Federal prohibition powers. The National Energy Conservation Policy Act of 1978 (NECPA, P.L. 95-619) required utilities to provide residential consumers free conservation services to encourage slower growth of electricity demand.[79]

4.2.4. Nuclear Power

During the decade of the 70's the commercial nuclear power industry was expanding rapidly throughout the nation. In California, there were two major nuclear units operating (Sacramento Municipal Utility District's Rancho Seco and Southern California Edison's San Onofre Unit 1). By the late 70's, PG&E had completed construction on the two Diablo Canyon units (1,100 MW each), but was precluded from operating them due to potential earthquake issues (later resolved during the 80's). In addition, SCE was in the early stage of construction on San Onofre Units 2 and 3 (1,100 MW each).

Inflation and real labor and materials cost increases quickly affected construction costs of nuclear power plants, while high interest rates raised financing costs. Capital costs rose from

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78. Energy Information Administration, "Fuel Choice in Steam Electric Generation: A Retrospective Analysis," Volume 1, Overview, Draft Report, Table 2.

79. Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970*

about $150 per kilowatt in 1971 to over $600 after 1976. Utilities building commercial nuclear facilities faced financial difficulties in justifying and meeting these increased costs[80]. Costs of nuclear power plants increased to over $2,000/kilowatt (kW) and coal plants to over $1,200/kW.

In March 1979, an event occurred at the Three Mile Island Unit 2 (Harrisburg, Pennsylvania) that resulted in the first case of melted fuel in a full scale commercial nuclear power plant. There had been prior cases of small scale fuel melting (e.g., the Fermi 1 reactor near Monroe, Michigan). Three Mile Island Unit 2 was the Nation's most significant commercial nuclear accident[81].

During the 70's, the climate between nuclear power advocates and environmentalists was confrontational. While voters failed to pass a 1972 proposal placing a 5-year moratorium on nuclear plant construction, conservation and environmental groups worked throughout the decade to stop construction of several proposed plants, especially along the coast and near fault lines.

In 1976, Governor Brown passed three nuclear safeguard laws; one of which included the provision that the Resources Conservation and Development Commission of California and the Legislature determine at least one method of disposing of radioactive waste material safely[82]. These safeguard laws, in essence created a moratorium on new nuclear power plant construction in California.

4.2.5. Public Utility Regulatory Policies Act of 1978 (PURPA) and Power Plant Industrial Fuel Use Act (PIFUA-1978)

PURPA and PIFUA, both passed in 1978 ushered in non-utility generation and limited use of gas in utility power plant due to a concern about a *gas bubble* and diminishing gas supplies. The PURPA law was a direct response to the increased concern over U.S. dependency on foreign oil in the wake of the OPEC oil embargos of the 70's and was also intended to encourage more energy-efficient and environmentally friendly commercial energy production. PURPA defined a new class of energy producer called a qualifying facility (QF). Qualifying Facilities (QFs) were defined as non-utility power wholesalers that were either co-generators, or small power producers using specified renewable energy resources. When a facility of this type met the FERC's requirements for ownership, size and efficiency, a utility company was obliged to purchase the energy from these facilities based on their avoided cost rates, established by the Public Utility Commissions. In California, these rates tended to be highly favorable to the producer, and were intended to encourage more production of this type of energy as a means of

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80. Energy Information Administration, *1983 Survey of Nuclear Power Plant Construction Costs*, DOE/EIA-0439(83) (Washington, DC, December 1983), p. 8.

81. http://www.nucleartourist.com/events/tmi.htm

82. http://infodome.sdsu.edu/about/depts/spcollections/collections/sdgesundesert.shtml

reducing emissions and dependence on other sources of energy[83]. In the late 70's and early 80's the CPUC took the next step in an attempt to break-up the utilities' monopoly over generation. The CPUC established four Standard Offer contracts (based somewhat on the various resource technologies) for QFs. The pricing structure was front loaded with high capacity payments and the avoided fuel cost was developed based on a forecast of oil being at $100 per barrel by 1990. The utility was required to accept energy from all QFs who signed a Standard Offer contract and could deliver or have it delivered to the investor-owned utility.

In combination, PURPA and PIFUA resulted in significant development of cogeneration facilities utilizing CCGT technology, development of independent non-utility owned power plants, development of renewables, and utility obligation to interconnect non-utility QF generation.

4.2.6. Regulation and Planning Process for the Investor-Owned Utility during the 70's

State of California:

- CPUC–the CPUC reviewed and approved generation and transmission projects and established retail rates. In stakeholder proceedings they also established avoided costs pricing for QFs.
- The California Energy Commission is the state's primary energy policy and planning agency. Created by the Legislature in 1974 (*Warren-Alquist Act*) and located in Sacramento, the Energy Commission has five major responsibilities:
  - Forecasting future energy needs and keeping historical energy data.
  - Licensing thermal power plants 50 megawatts or larger.
  - Promoting energy efficiency through appliances and building standards.
  - Developing energy technologies and supporting renewable energy.
  - Planning for and directing state response to energy emergency.

Federal:

- Federal Energy Regulatory Commission—FERC reviewed and approved hydro plant licensing, wholesale power and transmission service rates.
- The Federal Energy Regulatory Commission was chartered as a result of the Department of Energy Organization Act of 1977, signed by President Carter on August 4, 1977 and established within the Department of Energy.

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83. http://www.energyvortex.com/energydictionary/public_utility_regulatory_policies_act_of_1978_(purpa).html

- Nuclear Regulatory Commission[84]—NRC reviewed and approved nuclear plant licensing.

Transmission Planning:

- 70's—The transmission planning process consisted of:
  - Vertically integrated planning and review process.
  - Extensive coordination and review between sub-regions of the WECC.
  - WECC transmission project review for compliance with new planning standards.
  - While PURPA and PIFUA set in motion non-utility generation, it did not affect transmission planning until the mid-80's.

4.3. Muddle 80's

Figure APE- 3. Muddle 80's

The 80's started off the way the 70's ended; it was marked by high inflation, Iranian oil crises, escalating costs due to nuclear plant construction, almost no load growth, and high electric bills for the consumer.

Excess Capacity:

Starting in 1982 through 1988, there were seven nuclear units that came on-line that the California utilities either owned or participated in. These seven units added approximately 8,000 MW of capacity in the California and Desert Southwest region, with 5,400 MW of that capacity in California. The nuclear plants were:

- Diablo Canyon Units 1 and 2—each 1,100 MW (PG&E owner).
- San Onofre Units 2 and 3—each 1,100 MW (SCE, SDG&E, Anaheim and Riverside project participants).
- Palo Verde Units 1, 2, and 3—each 1,200 MW (LADWP, Southern California Power Authority and SCE—participants).

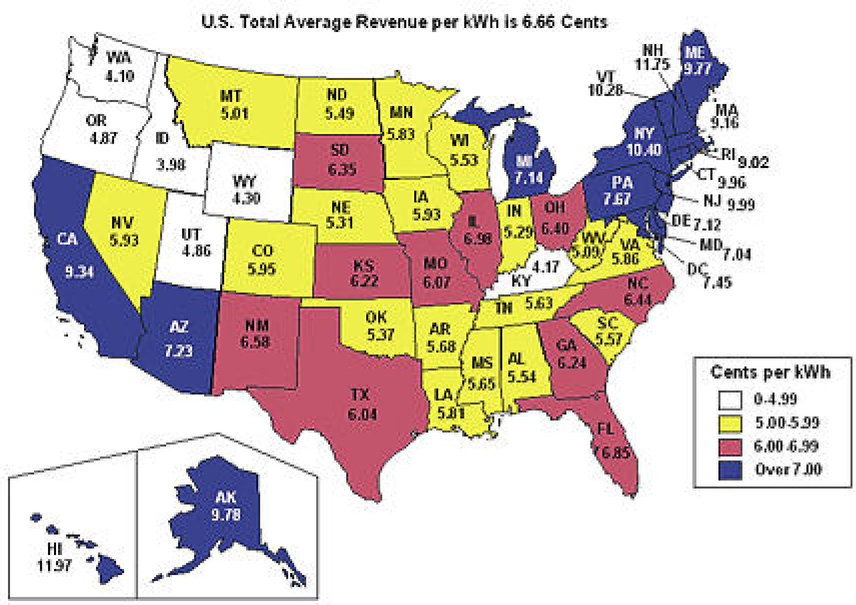
As stated earlier, PURPA was passed in 1978 and required a FERC jurisdictional utility to offer their avoided costs as payment for energy from a QF. As a result of this Act and the CPUC established high avoided costs, the California IOUs were obligated to contract for over 10,000 MW of QF energy and capacity, prior to the suspension of the Standard Offer contracts, in the late 80's. The net impact of the nuclear plants and the QFs additions, during a period of

84. NRC web site - http://www.nrc.gov/about-nrc/history.html#aec-to-nrc

slow load growth, left the utility with excess capacity. In some cases the installed capacity reserves were in the 30% range.

High Rates

The causes for the high consumer rates were a continuation of the high power plant fuel costs, sky rocketing construction costs for nuclear plants, high payments for QF energy and the continued double digit rate of inflation that was driving all operating costs higher within the utility. As an example of prices getting out of hand was nuclear construction cost. During the mid-70's the cost for a nuclear plant was approximately $600/per kilowatt and by early 80's the cost had doubled to approximately $1,200/per kilowatt[85]. The requirements and modifications coming out of the Three Mile Island event were significant drivers in the higher nuclear construction costs.



The average revenue per kWh of electricity sold is calculated by dividing revenue by sales. Average is for all sectors: residential, industrial, and commercial. Source: Energy Information Administration, Form EIA-861, Annual Electric Utility Report.

Figure APE- 4. U.S. Total Average Revenue Per kWH[86]

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85. Energy Information Admin., Survey of Nuclear Power Plant Construction Costs 1984, DOE/EIA-0439(84), pg. 13

86. SustainableFacility.com - http://www.sustainablefacility.com/CDA/Archives_EPM/d554b6f99be38010VgnVCM100000f932a8c0____

Slow Growth and Conservation:

The bottom line of all the above higher costs meant annual double digit rate increases for the consumer and as a result they continued their energy conversation efforts, with a net result of either a slowing or a negative load growth at the utilities.

Utility Diversification:

In the mid-1980's, there was much uncertainty as to the future direction of the electric industry partially as a result of FERC's PURPA and many industrial customers wanting to or converting from being a customers to cogeneration. To head off some of this uncertainty the electric utilities ventured into diversification, or expansion into non-regulated industries. This was made possible for some utilities because of large cash flows being available following completion of major plant construction programs in the early 1980's, the cash flows exceeded their immediate needs. Industry officials believe that usage of these cash flows to diversify into non-regulated industries would smooth out the financial risks of the regulated business, while providing companies an opportunity to earn returns above those allowed by regulation. To facilitate diversification, many electric utilities, formed holding companies under which the parent company holds both regulated and non-regulated subsidiaries[87].

There was mixed results from utilities venturing into diversification, those utilities that stayed in areas close to their core competence (power plant ownership and operations) were normally very successful, but for those who ventured far from their core competence (e.g., banking, small retail food stores, roofing, security services) it proved somewhat disastrous.

4.3.1. Regulation and Planning Process for the Investor Owned Utility during the 80's

State of California:

- CPUC—the CPUC reviewed and approved generation and transmission projects and established retail rates. In stakeholder proceedings they also established avoided costs pricing for QFs.
- The California Energy Commission is the state's primary energy policy and planning agency. During the 80's there primary focus was on licensing thermal QF power plants 50 megawatts or larger.

Federal:

- Federal Energy Regulatory Commission—FERC reviewed and approved hydro plant licensing, wholesale power and transmission service rates.
- Nuclear Regulatory Commission—NRC reviewed and approved nuclear plant licensing.

Transmission Planning:

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87. Peachtree Securities –
http://www.csb.uncw.edu/people/siglerk/classes/fin436/Fin%20436%20Cases/Case%207.doc

- 80's - The transmission planning process consisted of:
    - Vertically integrated planning and review process.
    - Extensive coordination and review between sub-regions of the WECC.
    - Transmission projects reviewed at WECC for compliance with planning standards and transfer capability ratings.
    - Transmission interconnections for QF power plants.

4.4. Restructuring – 90's

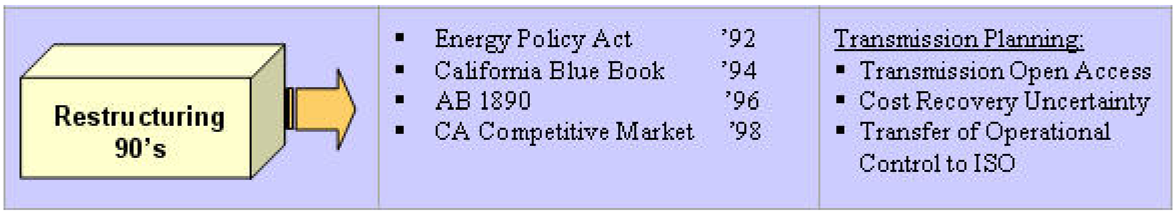

Figure APE- 5. Restructuring 90's

During the decade of the 80's several large industries in the U.S. underwent restructuring (e.g., airlines, gas, trucking and telecommunications) and appeared to be benefiting from less reliance on traditional regulation in favor of more reliance on market forces. In addition, in California, electric rates were too high and with the economy in recession, and the state looking for opportunities to bolster its competitive climate and attract new industry and jobs, it seemed eminently sensible to at least consider the idea of electricity restructuring at this time. At the federal level, there was support for further promoting non-utility generation through *exempt wholesale generators* which were exempted from state regulation, and further opening up access to utility transmission system. This was accomplished by the landmark Energy Policy Act of 1992.

4.4.1. Energy Policy Act of 1992 (EPAct 1992)

Similar to the PURPA legislation of the 70's, EPAct 1992 was enacted in response to concerns about America's oil dependence, raised by the 1991 Persian Gulf War. The purpose of EPAct 1992 was to create new energy regulations that would promote open access to transmission and increase competition in the wholesale energy markets[88].

The EPAct of '92 authorized FERC to require a jurisdictional entity, owning transmission, to provide transmission services, including any upgrades and expansion of transmission capacity necessary to provide transmission services to any one making such a request that is an electric utility, Federal Power marketing agency, or any other person generating electric energy for sale or resale.

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88. Document describing "What Public Power Utilities Must Know To Survive Under the Energy Policy Act of 2005" by Duncan & Allen

EPAct 1992 reformed PUHCA and created a new category of power producers called Exempt Wholesale Generators who would be exempt from PUHCA, subject to the FPA, not required to be a co-generator or renewable resource (PURPA QF requirements) and jurisdictional entities were not mandated to purchase power from them (which was a requirement under PURPA). To ensure the marketing of EWGs, the EPAct of 1992 instructed FERC to require jurisdictional utilities to make transmission service available at *just and reasonable* rates.

Following EPAct 1992, FERC issued Order Nos. 888 and 889 which identified the specific details and requirements for wholesale electricity transactions and established the requirement for entities to implement a real-time transmission trading system designed to better facilitate open access transmission service.

- Order 888 requirements:
  - Allow all electricity providers to have access to the transmission grid on equal terms for both point-to-point and network transmission services, including ancillary services.
  - Transmission Owner to file with FERC an open access transmission tariffs that is non-discriminatory.
  - Transmission Owners to take service under their filed tariff rates for their own wholesale electricity purchases and sales.
  - Transmission service to others shall be on terms *comparable* to how the utility served its native load and the obligation to offer ancillary services.
  - Reciprocity for public power and municipal entities.
- Order 889 requirements:
  - Implement an Open Access Same-time Information System (OASIS) that would provide all transmission customers with standardized electronic information on transmission capacity, prices, and other essential market information.
  - Transmission operations personnel at utilities function independently of generation and wholesale trading personnel.
  - Encourages the creation of FERC's jurisdictional ISOs.

4.4.2. CPUC's Blue Book - 1994[89]

On April 20, 1994, the CPUC issued its Blue Book, which announced the CPUC's intention to restructure the electric industry, and to begin the process of deciding formally how to go about it. CPUC had decided to create a future in which customers would have choice among competing generation providers and in which traditional cost-of-service regulation would be replaced by performance-based regulation. The issuance of the Blue Book marked the beginning

89. Center for Study of Markets - University of California.
http://repositories.cdlib.org/ucei/csem/CSEMWP-103

of a formal process to consider how the CPUC restructuring vision could be accomplished. Below are some of the desired attributes and issues related to a restructured electric industry:

- No customers would be forced to participate in direct access, if desired they could continue to receive bundled service from their local utility.
- The IOUs would be obligated to provide transmission and distribution services on a nondiscriminatory basis to direct access consumers.
- Development of energy markets vs. direct access—The CPUC had spent some time in the United Kingdom and liked the concept of a real-time market known as the *Pool*, The CPUC was fearful that direct access in the early stages of restructuring would possibly be a threat to the system reliability.
- Should the IOUs be ordered to divest themselves of their generating plants?
- Development of a non-bypassable c*ompetitive transition charge*. To cover the IOUs generation assets that was uneconomic in a competitive market.
- All continuing utility services would be regulated under new performance-based regulatory systems based on either a revenue or price cap framework.

4.4.3. State Legislation—AB1890

To fully implement restructuring of the electric industry required changes in legislation. The CPUC Blue Book approach polarized the utility industry and stakeholders to favor different approaches to deregulation. These competing visions were harmonized via a coalition of major interest groups (IOUs, large customers, environmental and consumer organizations) with support from the Governor of California, Pete Wilson. The chair of the Senate Energy, Utilities and Communication Committee (Steve Peace) held public stakeholder sessions to work on a single bill together. On August 31, 1996, the state legislature passed with complete unanimity the restructuring bill known as AB 1890, and the Governor signed it shortly thereafter.

The bill used the CPUC Policy Decision as a starting point. There were, however, several important provisions that either modified or redirected the CPUC in a few areas. Primary among these were:

- Going beyond the CPUC's call for a retail rate freeze it mandated a 10% rate cut during the four-year transition period that allowed for stranded asset cost recovery.
- Public purpose programs, most of which had been legislatively mandated, required modification in a restructured environment.
- Creation of the California Power Exchange (PX) to operate a day-ahead hour-by-hour spot market, in which generators could sell and retailers could buy power.
    - The IOUs, to ensure that the market would be liquid, were required to meet the energy demands of their native loads with energy purchases from the Power Exchange.
    - The IOUs were required to sell all the energy from their remaining generation assets through the Power Exchange.

- Creation of The California Independent System Operator to manage the IOU's transmission assets and to:
    - Maintain grid reliability.
    - Congestion management.
    - Providing ancillary services.
    - Real-time balancing between demand and generation.

4.4.4. California's Competitive Market

On April 1, 1998, the Power Exchange and CA ISO commenced operation. It was hoped that the creation of the Power Exchange and CA ISO would establish the necessary foundation for a successful competitive market. In addition, the three IOUs had divested themselves of their gas-fired generation and by 1999 the generation ownership in the CA ISO's control area was as indicated in

Table APE- 1 below:

Table APE- 1. Generation Ownership by Fuel Type

GW	Thermal	Hydro	Nuclear	QF (all types)	Other	Totals
PG&E	0.6	3.7	2.3	5.0		11.6
SCE	1.7 a	1.2	2.4 a	4.3		9.5
SDG&E			0.5	0.2		0.7
AES	4.7					4.7
Duke	2.9					2.9
Dynegy	2.9					2.9
Reliant	4.0					4.0
Mirant	3.2					3.2
Others	1.1 b	9.1			6.0 c	16.2
Totals	21.1	14.0	5.1	9.5	6.0	55.7

Source: California Energy Commission

Notes:

a Figures for SCE include coal and nuclear capacity located outside the State border

b Plant divested by the IOUs to companies with less than 1 GW of capacity in California (and, by implication, little market power)

c This is a residual for plant of all types apart from hydro, and includes 1.4 GW of geo-thermal plant divested by PG&E

The divested generation was purchased by five independent power producers (AES, Duke, Dynegy, Reliant, and Mirant), each purchasing roughly a fifth of the divested plant.

4.5. Regulation and Planning Process for the Investor-Owned Utility during the 90's:

State of California:

- CPUC—the CPUC reviewed and approved generation and transmission projects and established retail rates.
    - Identified the need for and foundation for a competitive electric market in California.

    - Implemented a cost recovery program for un-economical generation in a competitive market.
    - Established retail rate caps.
- The California Energy Commission is the state's primary energy policy and planning agency.

Federal:

- Federal Energy Regulatory Commission—FERC reviewed and approved hydro plant licensing, wholesale power, and transmission service rates.
    - Implemented EPAct 1992 action items related to electric industry.
    - Implemented OATs.
    - Implemented open access transmission same-time information system (OASIS).
- Nuclear Regulatory Commission—NRC reviewed and approved nuclear plant licensing.
- Transmission Planning:
- 90's - The transmission planning process consisted of:
    - Mandated and enforced separation between the utility merchant and reliability functions in both planning and operations.
    - IOU transmission proposals for new EHV lines or upgrades for the most part were rejected, e.g., Palo Verde Devers No. 2, third AC line.
    - New transmission interconnections built were almost exclusively by municipally owned utilities, e.g., 3rd AC Line, Mead-Adelanto, DC Upgrade.
    - Transmission upgrades were only developed, with internal approval, to meet reliability requirements and those significant RMR costs that were internalized by the transmission owners.
    - Transmission Owner projects had to be reviewed and approved by the CA ISO Planning Department.
    - WECC:
        - Extensive coordination and review between sub-regions of the WECC.
        - Post 1996 outage—WECC established rule –if you have not studied a condition you can't operate in that condition.
        - Developed and implemented Reliability Management Program in the WECC–mandatory standards.
        - Transmission projects reviewed at WECC for compliance with planning standards and transfer capability ratings.
- NERC—started initial process of establishing mandatory compliance with reliability standards.

4.6. Meltdown – 2000/2001

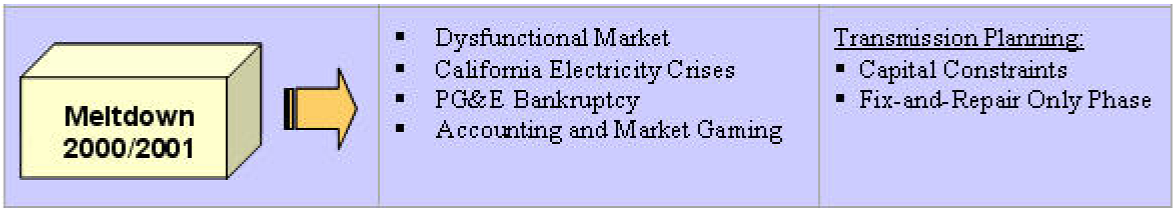

Figure APE- 6. Meltdown—2000/2001

4.6.1. Dysfunctional Market

During the spring of 2000 the California energy market began to collapse. In June the monthly mean energy price (see **Error! Reference source not found.** for the PX was almost $100 /megawatt-hour (MWh) higher than any previous month, going back to the start of the market. There were also numerous price spikes. Prices reached the CA ISO's $750/MWh price cap in either the real-time or ancillary service markets 23 times. In June the wholesale prices averaged $132/MWh. Wholesale price caps were lowered to $500/MWh in July and $250/MWh in August but average wholesale prices remained high during the summer. Wholesale prices eased somewhat during the fall but then spiked dramatically in December. By the end of January, the collapse was complete. Blackouts occurred on eight days during the winter and spring even though demand was far below the summer peak. The Power Exchange suspended operations, and the CA ISO, SCE, and PG&E were all insolvent.

All these long-term or external factors served to expose and amplify design flaws in an overly complex deregulatory scheme. The design flaws, notably a massive over-reliance on spot markets and capped retail prices, are often cited as the main reasons for California's problems, but all of the ingredients listed above contributed to creating the crisis[90].

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90. Center for Study of Markets - University of California.

http://repositories.cdlib.org/ucei/csem/CSEMWP-103,p. 21

Table APE- 2. California Wholesale Electricity Prices – Monthly Means ($/MWh)

	1998/9	1999/00	2000/1	2001
Apr	23.3	24.7	27.4	265.9
May	12.5	24.7	50.4	239.5
Jun	13.3	25.8	132.4	159.8
Jul	35.6	31.5	115.3	137.8
Aug	43.4	34.7	175.2	120.1
Sep	37.0	35.2	119.6	126.8
Oct	27.3	49.0	103.2	69.4
Nov	26.5	38.3	179.4	74.8
Dec	30.0	30.2	385.6	69.6
Jan	21.6	31.8	272.0	
Feb	19.6	18.8	304.4	
Mar	24.0	29.3	249.0	
Mean	26.2	31.2	176.2	

Sources: PX prices as reported in Joskow (2001) for 1998 through 2000; CAISO and CDWR data as reported by the CPUC (http://www.cpuc.ca.gov/static/industry/electric/electric+markets /historical+information/average+energy+costs+2000+thru+2001.xls) for 2001
Note: The prices for 1998 – 2000 are not strictly comparable to the prices for 2001 since the PX price is for day-ahead transactions while the CDWR data include prices for longer-term contracts.

4.6.2. California Energy Crises

By the beginning of 2001, the energy issues had progressed to a point that the CA ISO and two of the state's investor-owned utilities were deemed un-creditworthy and unable to purchase the necessary power to meet the customer demand. On January 17, 2001, then Governor Gray Davis proclaimed a State of Emergency in response to California's energy shortage. Following the Governor's Executive Order, and the signing of Senate Bill 7X two days later, a series of events occurred that would keep electricity flowing to Californians through the critical summer months and thereafter. On February 1, the governor signed legislation (AB1X) that gave the California Department of Water Resources (DWR) the authority to purchase energy on behalf of the retail customers of the Investor-Owned Utilities (IOUs). The California Energy Resources Scheduling (CERS) division was set up within DWR take on this responsibility. The role of CERS later developed from the emergency mandate to include responsibility for gas management planning, procurement and administration of short-term and long- term power contracts, and continued power supply planning and resource scheduling[91].

4.6.3. Pacific Gas & Electric Bankruptcy

On Friday, April 6, 2001, Pacific Gas & Electric (PG&E), after accumulating about $9 billion in debt, filed for Chapter 11 bankruptcy. PG&E's bankruptcy filing was a result of them being caught by the high cost of energy they purchased from energy suppliers and the fact they could

91. History of CERS –
http://wwwcers.water.ca.gov/pdf_files/about_us/cershistory.pdf

not recover those costs through their authorized rates. The Governor had proposed a plan that he would allow retail rates to increase, but only after PG&E (as well as SCE) sold the state their transmission assets as payment for the debt and, in addition, agreed to provide energy for ten years. This plan was unacceptable to PG&E and they elected to seek protection under Chapter 11, allowing them to continue operations, until they could get things worked out with the state and their creditors[92].

4.6.4. Accounting and Market Gaming

In FERC's report, *The Commission's Response to the California Electricity Crisis and Timeline for Distribution of Refunds,* dated December 27, 2005, they concluded there were several factors contributed to the energy crises in California between January of 2000 and June of 2001, such as:

- Flawed market rules.
- Inadequate addition of generating facilities in the preceding years.
- A drop in available hydropower due to drought conditions.
- A rupture of a major pipeline supplying natural gas into California.
- Strong growth in the economy and in electricity demand.
- Unusually high temperatures.
- An increase in unplanned outages of extremely old generating facilities.
- Market manipulation by some sellers.

As of the date of the above mentioned report, FERC had completed all but one of the 60 investigations regarding market manipulation and that their staff had facilitated settlements resulting in over $6.3 billion for issues regarding allegations of market manipulation in the West during the period, as well as settlements involving whether prices were justness and reasonableness[93].

4.6.5. Regulation and Planning Process for the Investor-Owned Utility, during the Energy Crisis

State of California

- CPUC—Focus shifted to control damage from the energy crises:
    - Restore IOUs creditworthiness.
    - PG&E bankruptcy.
    - Adequate supplies to meet customer loads.

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92. CNN story - http://transcripts.cnn.com/TRANSCRIPTS/0104/06/bn.06.html

93. The Commission's Response to the California Electricity Crisis and Timeline for Distribution of Refunds", dated December 27, 2005 - http://www.ferc.gov/legal/staff-reports/comm-response.pdf

- Governor’s Office—Worked with legislators, state commissions, IOUs and industry stakeholders to develop a strategy to:
    - Get sufficient generation resources under long-term contracts.
    - Stabilize a dysfunctional market.
    - Establish a portfolio management organization and an energy purchasing agent for the IOUs.
- The California Energy Commission is the state's primary energy policy and planning agency.

Federal

- Federal Energy Regulatory Commission—One of their primary roles and responsibilities for FERC in the development of competitive wholesale markets **should** have been to provide:
    - Oversight and market monitoring functions.
    - Take the necessary corrective action when a market became dysfunctional.
- Nuclear Regulatory Commission—NRC was very concerned regarding the financial health of the three California IOUs and the implications it could have on the safe operation of San Onofre and Diablo Canyon nuclear units.

Transmission Planning

- Energy Crisis Years—the transmission planning process remained the same as in the 90’s, but due to the utilities financial situation and a need to conserve scarce capital, the mode of operation was to perform fix-and-repair work only. No major new transmission projects were built due to financial constraints and regulatory focus on the energy crises.

4.7. 2005 +

Figure APE- 7. Energy Policy Act 2005[94]

The Energy Policy Act of 2005 (EPAct 2005) was signed into law on August 8, 2005. The purpose of the EPAct 2005, as it relates to the electric industry, was in response to the many weaknesses resulting from the disparate changes associated with electric industry restructuring. The

94. EEI’s web site - Energy Policy Act of 2005 – Summary of Title XII – Electricity, Title XVIII – Studies and Related Provisions

industry restructuring had its roots with the passage of Energy Policy Act of 1992 and the subsequent FERC Order Nos. 888 and 889. Under 888 and 889, the FERC jurisdictional utilities transitioned from the traditional vertically integrated utility to the unbundling of generation, transmission, and distribution. In addition, as a result of the EPAct 2002, FERC was driving the jurisdictional utilities to put their transmission assets under the control of an Independent System Operator (ISO) and later a Regional Transmission Organization (RTO).

EPAct 2005 addresses the following topics and issues:

- Grid reliability—the formation of an Electric Reliability Organization (ERO) and making electric reliability standards mandatory on all users, owners, and operators of the nation's transmission system.
- Transmission siting rules—the EPAct grants FERC, for the first time, the authority to approve the siting of electric transmission facilities located in *national interest electric transmission corridors* if states cannot or will not act in a timely manner to approve the siting. The U.S. Department of Energy (DOE) was established as the lead federal agency for purposes of coordinating all federal approvals and related environmental reviews related to siting transmission facilities. In addition, DOE is required, every three years, to identify *national interest electric transmission corridors* (a.k.a. congested or constrained transmission paths).
- Native Load Service Obligation – a new Section 217(b)(4) of the FPA requires FERC to exercise its FPA authority to facilitate planning and expansion of transmission facilities to satisfy LSEs obligations to retail customers and their ability to secure firm transmission rights to meet such obligations.
- Markets—establish rules that addresses market transparency and market manipulation.
- PUHCA—repeals the Public Utility Holding Company Act of 1935 to encourage investment in the nation's electricity infrastructure.
- Transmission technology—requires FERC to encourage advanced transmission technologies that increase the capacity, efficiency or reliability of existing or new transmission facilities.
- Non-jurisdictional Entity—FERC may require, with a few exceptions, an *unregulated transmitting utility* to provide transmission service at rates that are comparable to those it charges itself and on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission service to itself and that are not unduly discriminatory or preferential.
- Transmission Infrastructure Investment—requires the FERC establish rules, for utilities under an ISO/RTO, that provide transmission rate incentives to benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.

California Market Redesign[95]

On June 24, 2004, the CA ISO Board of Governors approved a market redesign and technology upgrade program for the CA ISO in order to gain economic and technical efficiencies. The program will be operational in 2008:

- Market improvements to assure grid reliability and more efficient and cost effective use of resources. The CA ISO to conduct a Day-Ahead Market that combines three services; energy, ancillary services (operating reserves) and congestion management to better match what really happens when the electricity flows. The Day–Ahead Market will determine the best use of resources available and identify the least cost method of procuring required components.
- New Market Rules—the market redesign introduces new market rules and penalties that prevent gaming and manipulation. Through revised tariffs the CA ISO has been granted new authority by the FERC to assess financial penalties on market participants that do not comply with instructions from the ISO control room. The new market design also determines the deliverability of all schedules, rejecting requests that are physically impossible.
- Locational Marginal Prices (LMP)—LMP will identify the cost of producing power as well as the cost of delivery. This information gives the CA ISO and market participants a clearer picture of the true cost of getting power to areas that may not have enough local generation or where transmission capacity is lacking.
- Technology upgrades to strengthen the entire CA ISO computer backbone. The technology upgrades will provide a more precise model of the grid using the latest computer technology to allow the CA ISO to better predict how energy scheduled a day-ahead of time will flow in real-time. The CA ISO will be able to see all potential transmission congestion a day-ahead of time, rather than waiting until real-time.

CPUC - Procurement and Resource Adequacy (RA)[96]

California's RA policies have been under development for several years, but the first active compliance period commenced in June 2006. The purpose of the program is for the review and approval of:

- Plans for the utilities to purchase energy.
- Policies that address utility cost recovery for energy purchases.
- Programs that ensure that the utilities maintain a set amount of energy above what they estimate they will need to serve their customers (called a reserve margin).
- Implements a long-term energy planning process.

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95. Basics of MRTU - http://www.CA ISO.com/docs/2005/02/22/2005022208442727277.pdf

96 CPUC - Procurement and Resource Adequacy - http://www.cpuc.ca.gov/static/hottopics/1energy/r0404003.htm

California's Renewable Portfolio Standard (RPS)[97]

In 2002, Senate Bill 1078 (SB 1078, Sher, Chapter 516) established the RPS program, which requires an annual increase in renewable generation by the utilities equivalent to at least 1% of sales, with an aggregate goal of 20% by 2017. The CPUC accelerated the goal, requiring the IOUs to obtain 20% of their power from renewables sources by 2010 (Senate Bill 107 codified this goal in state law). Currently, the Commission is considering ways to achieve 33 percent renewable energy by 2020.

RPS - Actual renewable deliveries in 2005:

- PG&E – 13.5 % (9,801 GWh).
- SCE – 17.7% (13,195 GWh).
- SDG&E - 5.5% (830 GWh).

New Transmission Projects Being Proposed

Recently, there has been much discussion regarding the construction of new EHV transmission lines in the Western Interconnection. The governors of California, Nevada, Utah and Wyoming had proposed a new interstate EHV transmission line across the Western U.S., from Wyoming with terminal connections in Utah, Nevada and California. Some of the Arizona utilities and others are considering an EHV transmission project from Wyoming to the Desert Southwest area, and PG&E has proposed an EHV project from British Columbia to Northern California.

97. CPUC RPS Program - http://www.cpuc.ca.gov/static/energy/electric/renewableenergy/index.htm

Appendix F

Existing Process for Transmission Project

Approvals and Case Histories

List of Figures

List of Tables

The historical CA ISO transmission planning process consisted of:

1. The Participating Transmission Owners (PTOs) submitted yearly transmission assessment and expansion plans to the CA ISO covering the next five years in detail plus a tenth year. The CA ISO reviewed the assessment to ensure it was adequate. The expansion plans were reviewed to determine if the proposed projects: (1) solved an identified problem; (2) were the best alternative from a system point of view; and, (3) were the most economical alternative.
2. CAISO management approved projects that met the CAISO evaluation criteria and had an estimated cost below $20 million or submitted the project for CA ISO Board approval if they had an estimated cost exceeding $20 million.

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98. Basics of MRTU - http://www.CA ISO.com/docs/2005/02/22/2005022208442727277.pdf

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Maturing CA ISO Transmission Planning Process

In a letter, date 8/01/05, from Armie Perez, at that time Director of Transmission Planning, he described the historical CA ISO planning process as follows[101]:

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99. CPUC - Procurement and Resource Adequacy - http://www.cpuc.ca.gov/static/hottopics/1energy/r0404003.htm

100. CPUC RPS Program - http://www.cpuc.ca.gov/static/energy/electric/renewableenergy/index.htm

101. A. J. Perez Letter, dated 8/01/05 –

1. The Participating Transmission Owners (PTOs) submitted yearly transmission assessment and expansion plans to the CA ISO covering the next five years in detail plus a tenth year. The CA ISO reviewed the assessment to ensure it was adequate. The expansion plans were reviewed to determine if the proposed projects: (1) solved an identified problem, (2) were the best alternative from a system point of view, and (3) were the most economical alternative.
2. CA ISO Management approved projects that met the CA ISO evaluation criteria and had an estimated cost below $20 million or submitted the project for CA ISO Board approval if they had an estimated cost exceeding $20 million.
3. Additionally, the CA ISO combined the individual PTOs plans submitted into one and performed an independent and comprehensive analysis to make sure that "nothing fell through the cracks".
4. Finally, the CA ISO conducted studies to determine Reliability Must Run (RMR) Generation requirements.

In 2005, CAISO revamped its transmission planning process to be more proactive. As a result of the CA ISO's reassessment of their transmission planning process the following Figure 1 and Figure 2 will show how the new process is more interactive and involved all stakeholders:

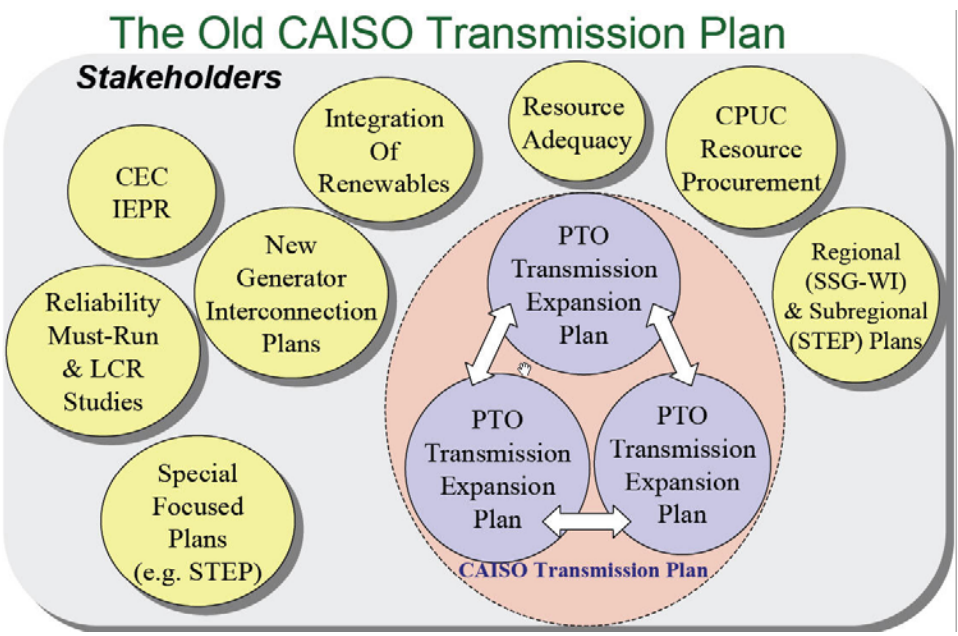

Figure APF- 1. CA ISO's Old Transmission Planning Process

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http://www.CA ISO.com/docs/2005/08/01/2005080111170126493.pdf

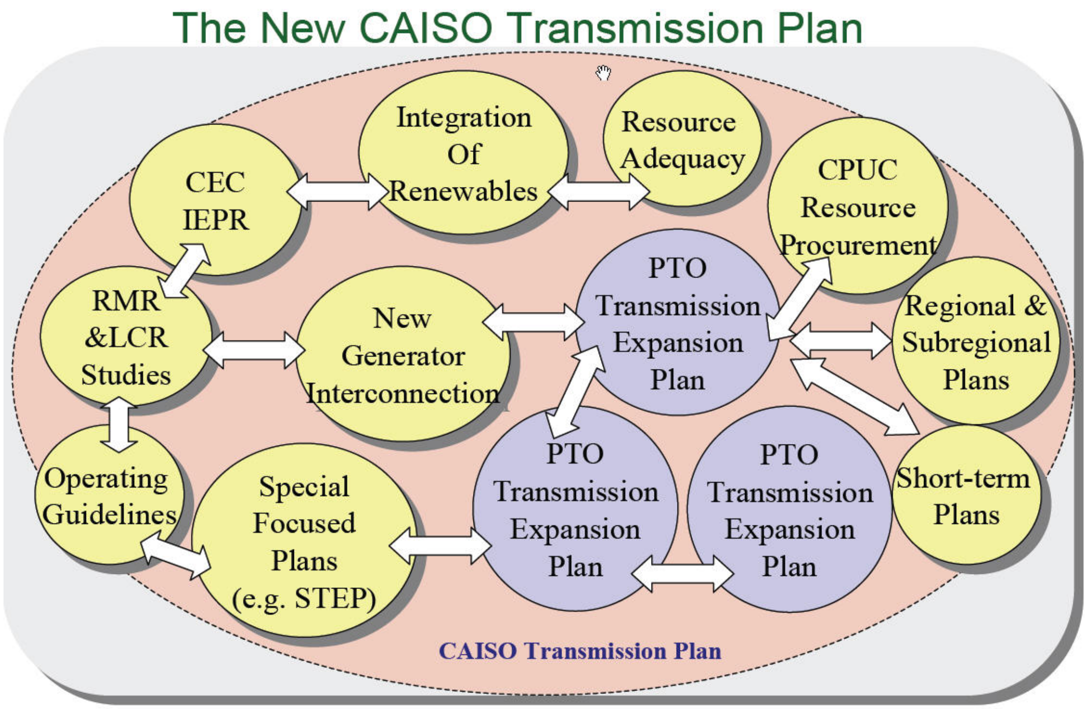

Figure APF- 2. CA ISO's New Interactive Transmission Planning Process

4.7.1. FERC Becomes Project Backstop

EPAct 2005 granted FERC limited backstop authority to site electric transmission facilities located in national interest electric transmission corridors if states cannot or will not act[102].

4.7.2. Regulation and Planning Process for the Investor-Owned Utility 2005 and Beyond

State of California:

- CPUC – Planning for the future:
    - Long-term Planning—Implemented resource procurement proceedings.
    - Resource Adequacy and Local Area Requirements—Work with the CA ISO to identify zonal and local area resource requirements and LSE's reserve requirements.
    - Work with the Energy Commission to implement renewable procurement standards.

102. FERC Press Release - http://www.ferc.gov/press-room/statements-speeches/kelly/2006/06-15-06-kelly-C-1.asp

- Governor's Office—through the Western Governors Association, establish a vision for EHV transmission projects in the Western Interconnection.

- The California Energy Commission
    - Primary organization for long-term growth forecast.

Federal:

- Federal Energy Regulatory Commission
    - Implement EPAct 2005 requirements.
    - Backstop authority for transmission projects.
    - Enforcement agency for mandatory reliability.
    - Expanded authority over jurisdictional and non-jurisdictional entities.
- Nuclear Regulatory Commission
    - Continue oversight of nuclear plant operations.
    - Review request for proposed new nuclear plant construction.

Transmission Planning:

- Maturing CA ISO transmission planning process that is highly dependent on stakeholder input and interactions.
- Greater interaction and coordination with California agencies (e.g., CPUC and Energy Commission).
- Significant interaction with WECC sponsored regional transmission planning groups.

Recent Transmission Projects

1. **Path 15 – Completed**. Path 15 is an 84-mile stretch of electrical transmission lines in the Central Valley connecting Southern California with the northern part of the state. The existing transmission system in this area was insufficient to transmit the necessary energy in a south-to-north direction. Building a third 500 kilovolt (kV) transmission line and other upgrades provided an additional 1,500 megawatts of transfer capability (s-to-n) for a cost of approximately $250 million

Figure APF- 3. Path 15 (source CA ISO)

2. **Tehachapi – Several phases approved**. The purpose of the project is to interconnect and integrate forecast development of renewable energy projects totaling 4,500 MW. The project will be built in eleven (11) phases with a total cost of approximately $1.8 billion.

Online	Seg	Description	Cumulative Capability*
2008	1	Antelope-Pardee 500 kV T/L and Antelope Expansion	300
2009	2	Antelope-Vincent No.1 500 kV T/L	700
2009	3	Antelope-WindHub 500 kV & WindHub-HighWind 220 kV	
2011	5	Antelope-Vincent No.2 500 kV T/L	2,200
2011	4	Antelope-Whirlwind 500 kV and Whirlwind-Cottonwind 220 kV T/L Facilities	
2011	9	Increase Operation to 500 kV/Transformer Banks/Substation Equipment/ Static VAR Compensators	
2011	10	New Whirlwind-Windhub 500 kV T/L	
2011	6	New Replacement Vincent-Rio Hondo No.2 500 kV T/L	
2012	7	New Vincent-Mira Loma 500 kV T/L (portion between Vincent-Mesa Area)	
2012	8	New Vincent-Mira Loma 500 kV T/L (portion between Mesa Area-Mira Loma)	
2013	11	New Vincent-Mesa (via Gould) 500/220 kV T/L	4,500

Figure APF- 4. Tehachapi Renewable Project (source SCE)

3. **Palo Verde Devers No. 2 – Approved**. A second 500 kV transmission line that extends 230 miles along the existing right-of-way between SCE's Devers Substation near Palm Springs and the Palo Verde Generating Station switchyard west of Phoenix, Ariz. This project would facilitate the delivery of new merchant generation from the Palo Verde area to California. The project is expected to add an additional 1,200 MW of transfer capability between Arizona and Southern California, for a cost of approximately $680 million.

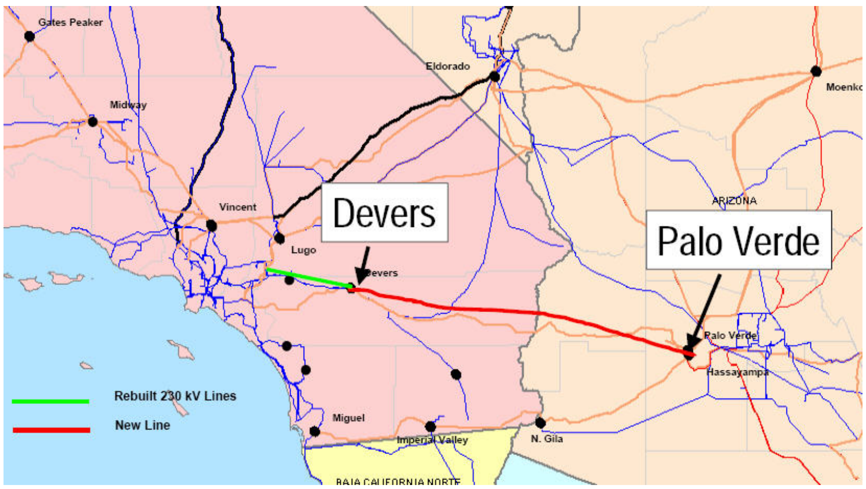

Figure APF- 5. Devers-Palo Verde #2 500 kV line (source CA ISO)

4. Major System Reliability Upgrades on IOU Systems - Implemented

5. Trans Bay Cable – Final Stages of Licensing - The project is being developed to supports the energy import requirements into the San Francisco peninsula. The line consists of a HVDC cable (+- 500 kV) with a transfer capability of approximately 400 MW, at a cost of $300 million.

Figure APF- 6. Trans Bay Cable Project (Source Babcock and Brown)

Projects Proposed and Under Discussion

6. **Sunrise Powerlink and the Green Path.** The project consists of approximately 100 miles of 500 kV as well as some new 230 kV lines. The projects would achieve three objectives, 1) ensure in-area reliability, 2) ability to import renewable resources and 3) reduce fuel cost from increased energy imports. The cost of the project ranges from $1 billion to $1.5 billion.

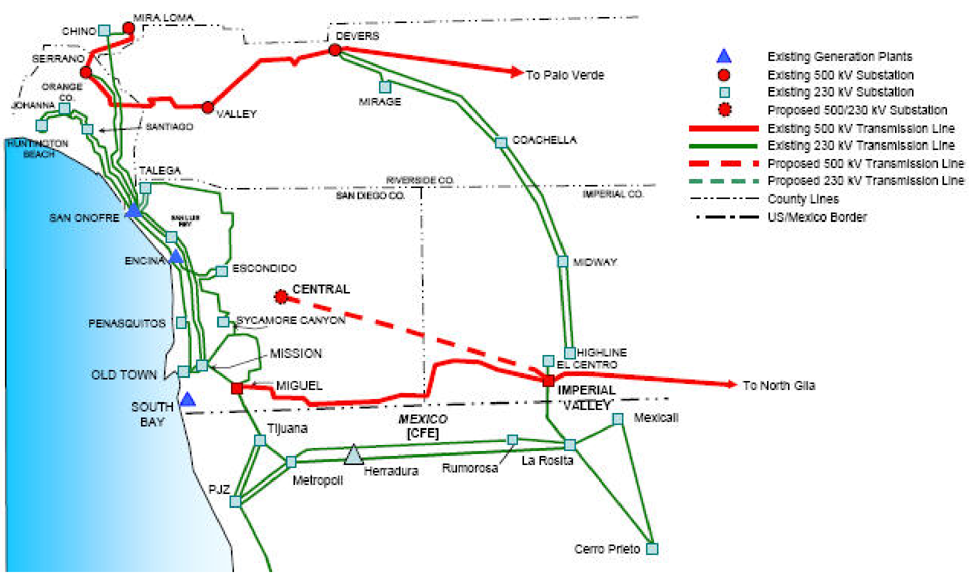

Figure APF- 7. Sunrise Powerlink (source SDG&E)

7. **Green Path.** The Green Path Project will improve the grid reliability within the IID service area and facilitate exporting the geothermal energy from the Imperial Valley to

the rest of the state. Cost of the project is approximately $430 million. The project participants have agreed to link the Green Path Project with SDG&E's Sunrise Powerlink at Imperial Substation.

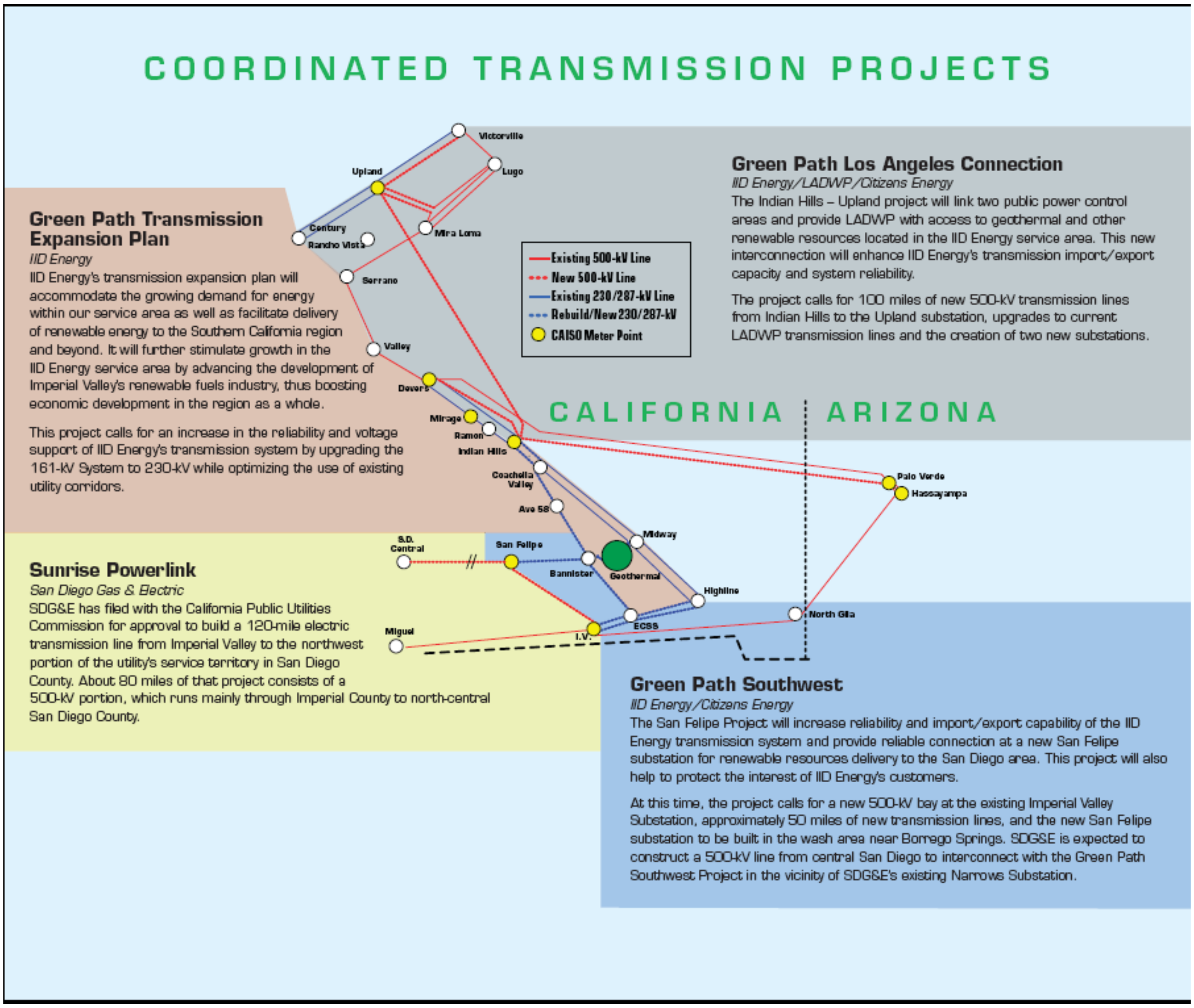

Figure APF- 8. Green Path Project (Source Imperial Irrigation District)

8. **Frontier Line.** The Governors of California, Nevada, Utah and Wyoming agreed to support developers seeking to build the $5 billion Frontier Line transmission project, which will allow access to the State of Wyoming's vast coal resources and potential development of renewable resources.

9. **British Columbia to Northern California.** Pacific Gas & Electric Company (PG&E) has initiated the WECC Regional Planning Project Review of electric transmission alternatives to connect Canada and the Pacific Northwest to Northern California. Potential project alternatives would include both 500 and 765 kilovolt (kV) alternating current (AC) and high voltage direct current (HVDC) lines, via overhead or undersea routes.

The proposed line is intended to provide three main benefits:

- Access to significant incremental renewable resources in Canada and the Pacific Northwest.
- Improved regional transmission reliability.
- The potential capacity for a line(s) is up to 3000 MW (1600 – 2000 MW for the DC submarine cable option).

10. **Central California Clean Energy Transmission Project [103].** Pacific Gas & Electric Company has proposed a new 150-170 mile 500 kV line between Midway Substation and the Fresno area on new R/W. The project would increase the Path 15 transfer capability by approximately 1,250 MW. The project has an operating date of 2013 at a cost of $0.7 to 1 billion. Benefits of the project are:
    - Helps integrate southern California renewables with northern California.
    - Increase utilization of the Helms PSP to enhance the value of off-peak generation.
    - Increase reliability to Yosemite/Fresno area.
    - Reduce Fresno Area local capacity requirement.

103. Central California Clean Energy Transmission Project - http://www.energy.ca.gov/2007_energypolicy/documents/2007-05-14_workshop/public_comments/PG+Es_2007-05-14.PDF

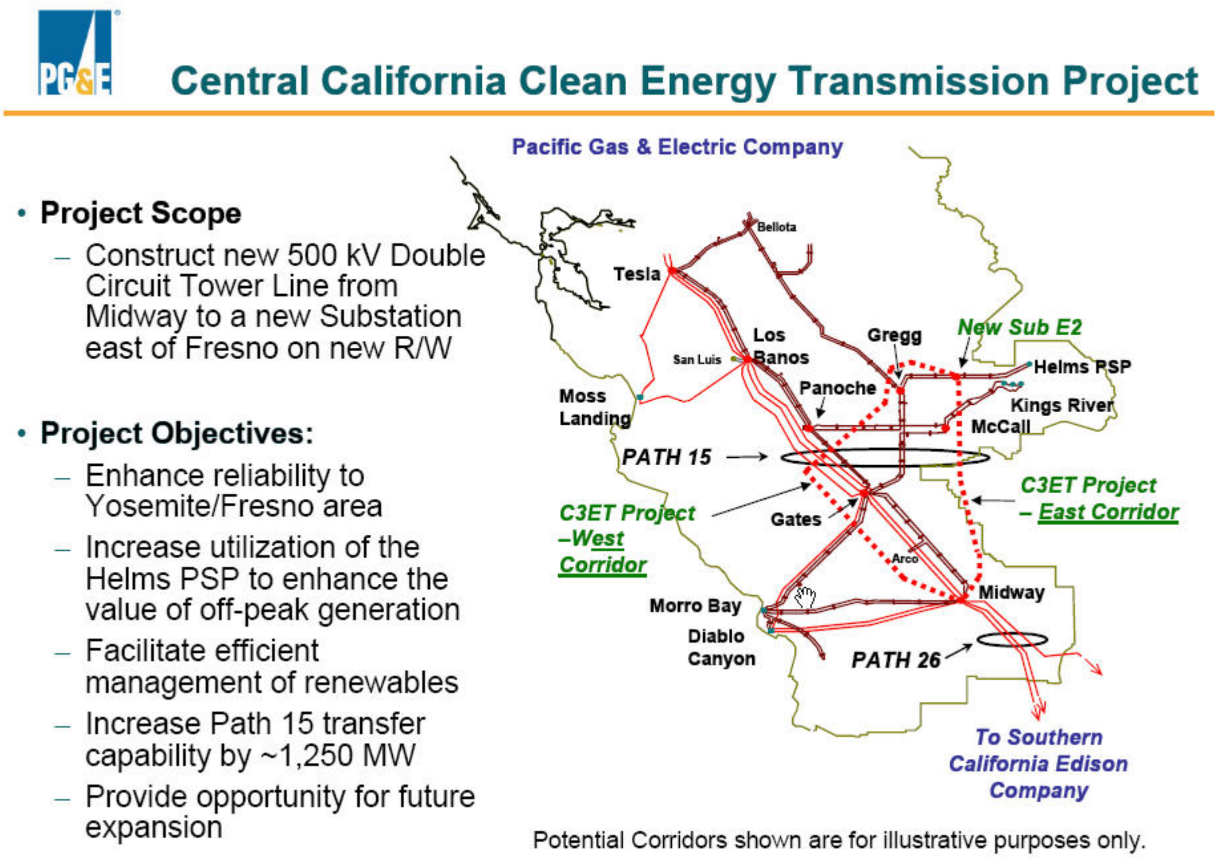

Figure APF- 9. PG&E's Proposed Central California Clean Energy Transmission Project (source PG&E)

4.8. Current Transmission Planning in California

For the three investor-owned utilities in California, the focus of transmission planning has shifted to CA ISO. The CA ISO transmission planning process is maturing. The key issues are:

- Renewables integration.
- Stakeholder participation.
- Transmission project economic evaluation methodology.
- Market information on new generation for use in transmission planning.
- Coordination and collaboration with CPUC, Energy Commission, and other state agencies.

To the extent that new transmission is within the CA ISO footprint and transmission costs are rolled into the CA ISO TAC, the issue of cost allocation and cost recovery is moot. However, for transmission projects involving multiple jurisdictions or where the project does not receive rolled in rate treatment, the issue of cost allocation among jurisdictions and participating utilities and associated tariff-based cost recovery becomes critical.

4.9. Research Findings and Conclusions

As the research team reviewed the many industry changes over the past five decades they found the changes have impacted the transmission planning process in the following five (5) key areas:

1. The traditional utility planning process transitioned from vertically integrated to disaggregated planning for transmission and generation.
2. Utility-led to ISO-led transmission planning with stakeholder participation.
3. Utility footprint planning to regional planning with stakeholder participation.
4. Utility transmission usage rights to open access policy.
5. Separation between the generation and transmission functions—no information sharing or planning coordination, making transmission planning more difficult.

Table APF- 1 provides a recap of the changes that have occurred in the various phases of the California transmission planning process.

Table APF- 1. Recap of Changes and the Impacts on Transmission Planning for the California IOUs

Function	Historical	Current
Planning - Local	Utilities	CA ISO with stakeholder participation
Planning – Regional	Footprint Utilities	WECC utilities with regional stakeholder participation
Industry	Vertically Integrated	Separation of Generation & Transmission Functions
Generation Siting	Utility	IPP or Utility
Project Sponsorship and Ownership	Utility	Utility, ITC, Stakeholders
Project Purpose	Integrate New Generation and Access to Resources	Meet market needs and policy mandates – renewables, generation, reliability, congestion
Usage Rights	Owners	Open Access
Cost Recovery	CPUC Approved Rates	FERC approved rates – rolled into CA ISO TAC
Transmission Siting	CPUC	CPUC or other lead environmental review agency
Project Approval	CPUC	CA ISO, CPUC, FERC (Backstop Authority)
Rate Recovery	FERC – Transmission CPUC – Retail Rates	FERC – Transmission; CPUC – retail & backstop authority for renewable transmission
Reliability Requirements	Good Utility Practices	National and WECC Mandatory Standards

Appendix G

Fact Sheet

TRANSMISSION RESEARCH PROGRAM

June 2008

BENEFIT QUANTIFICATION AND COST ALLOCATION RESEARCH PROJECT

There is general policy consensus on the need for new transmission projects to advance the policy objectives of renewables integration, reliability management, efficient market operations, interconnect new load and generators, reduce transmission congestion and bottlenecks, and expand access to regional power markets. Historically, major transmission projects were sponsored and owned by utilities and generally proposed as part of new power plant development by integrated utilities.

This landscape has changed with the separation of generation and transmission assets and separation of transmission operations from ownership by shifting the responsibility of transmission operations from utilities to Independent System Operators/Regional Transmission Operators (ISOs/RTO's) such as CA ISO. These changes in industry structure, operations, and planning impact how new transmission projects are planned, evaluated and approved. Approval of proposed major regional transmission projects in this new environment has proved to be challenging, witness the difficulty in moving forward with several California based projects such as the Palo-Verde Devers No.2 line, Sunrise, Greenpath, and others. This difficulty has brought into focus the need for research on benefit quantification and cost allocation methods to help with the approval of major regional transmission projects.

Problems Addressed

This project was commissioned to perform a scoping study to understand transmission benefit quantification, cost allocation, cost recovery and project approval processes with a particular focus on recommending methods for improved benefit quantification and cost allocation that better fits the new electric industry structure and planning environment.

The research focus was to identify different benefit streams, outline methodologies to quantify benefits including strategic benefits that have in the past been handled qualitatively, and outline approaches for assessment of benefits and assignment of benefits that could be factored into project cost allocation and cost recovery decisions of major transmission projects that may involve multiple utilities and regulatory jurisdictions.

Background

Utility efforts to develop new transmission projects that are local in nature, address well documented reliability needs, are required for interconnecting new load or generation are generally supported and have been gaining regulatory approvals and stakeholder support. However, major regional transmission projects that involve multiple jurisdictions and utilities and are needed for integrating remote renewable resources, reducing costs, improving market operations, providing long term strategic benefits and improving operating flexibility, don't have a clear path forward. Projects cannot go forward without cost recovery certainty. Cost recovery certainty requires allocation of costs through tariffs or contracts. For a major regional transmission project involving multiple jurisdictions and utilities to go forward, there needs to be a consensus on benefits, costs, and allocation of benefits and costs that can be embraced by stakeholders and policymakers.

The challenge associated with benefit quantification, cost allocation, and approval of new transmission projects was recognized in a September 2007 report prepared by The Blue Ribbon Panel on Cost Allocation[104].

While the wholesale electricity market has changed fundamentally, the framework for enabling and encouraging investment that will better enable the grid to serve growing competitive markets has not yet fully emerged. One area still largely unresolved is how the costs incurred in transmission expansion will be allocated among users. While it is clear that many traditional cost-allocation approaches are no longer appropriate, new principles governing the allocation of cost responsibility for new transmission investment have yet to be fully articulated and implemented.

Project Goals

A summary of the goals of this project are:

1. Assess current methods and develop recommendations to improve benefit quantification methods.
2. Describe benefit quantification and cost allocation approaches and how they may be utilized to inform policy discussions, regulatory proceedings and stakeholder processes related to transmission projects.
3. Identify areas for research to improve the state-of-the art for benefit quantification.

The project is not attempting to achieve stakeholder consensus with respect to research findings and recommendations on benefit quantification or to suggest a specific methodology for any proposed transmission project. The research is focused on developing a framework for use in transmission planning and approval processes.

Topics Researched and Addressed

There are many key policy questions that came up as part of this research, for example impact of transmission technologies, impact of industry and regulatory changes, and lessons from other regions and industries. The full range of topics addressed as part of the project research and key conclusions include:

- Transmission Technologies – How do they impact benefits, influence cost allocation, impact stakeholders?
  - Technologies Impact Line Capacity or Ratings, Power Flows, Grid Reliability
  - Selection of technologies impacts size of benefits and distribution of benefits
- Industry and Regulatory Changes – How have things changed and what does it mean for large regional transmission projects?
  - Shift from utility centric integrated planning to regional planning with stakeholder participation
- Review of Other Regions and Industries – What can we learn and apply for transmission in California and the Western Interconnection?
  - ISOs have similar planning processes
  - Jointly owned multi-jurisdictional projects are almost exclusive to the west
  - ISOs moving towards postage stamp (everybody pays) approaches with FERC encouragement
  - Transparency in transmission planning, predictable cost allocation/cost recovery methods, and length of experience with planning process is important for acceptance by stakeholders
  - Telecom and gas industries are indeed different – property rights

The research focused on assessment of Benefit Quantification, Cost Allocation, and Approval Processes and Recommendations for improvements in methods.

104. The Blue Ribbon Panel on Cost Allocation, Sept 2007, *A National Perspective On Allocating the Costs of New Transmission Investment: Practice and Principles*, p 1.

Benefits of the Project

The investigation identified seven research methods that can augment existing benefit quantification approaches to quantify the full range of transmission project benefits – these seven methods are:

1. Public Good – long asset life benefit–use of social rate of discount
2. Fuel Diversity Benefit–renewable resource integration
3. Reliability Improvement from Extreme System Multiple Contingency Events–new concepts
4. Risk Mitigation for Low Probability/High Impact Extreme Market Events–new concepts
5. Incorporate societal or strategic benefits through processes that lead to stakeholder consensus
6. Resource Portfolio Analysis
7. Dynamic Analysis (impact of new transmission on construction of new generation in the exporting region)

Application of Improved Benefit Quantification Approaches

Utilizing the seven proposed research methods to quantify the benefits of transmission projects will enable policymakers, utilities, and stakeholders to quantify the benefits for projects, understanding distribution of benefits among participants, and enabling each utility or jurisdiction to evaluate the impacts on their individual constituency. The different uses of the benefit quantification methods for proposed new transmission projects include:

- Calculating and quantifying the distribution of benefits among participants and jurisdictions.
- Demonstrating and sharing benefits for direct and indirect participants and critical stakeholders.
- Enabling each utility or jurisdiction to analyze benefits of projects (or package of projects)
- Providing guidance on cost allocation among multiple participants and jurisdictions
- Selecting cost recovery methodology.

Project Objectives and Work Scope

This research project included the following tasks.

Task 1: Benefit Streams, Quantification Methods, Cost Recovery, Recent Transmission Projects

Task 2: Framework to Evaluate Future Transmission Projects and Benefits

Task 3: Research Cost Recovery and Cost Allocation Methodologies

Task 4: Review Technology Options and Impact on System Utilization and Cost Allocation

Task 5: Review and summarize examples of alternative approaches that have been utilized for transmission project approvals.

Task 6: Review existing process for transmission line approval, rate determination and cost recovery.

Task 7: Reports and Briefings

Task 8: Technical Advisory Committee (TAC)

A TAC was formed to serve as a sounding board for the research project and provide feedback on research direction. The TAC is comprised of:

- Dede Hapner, Vice President, FERC and ISO Relations, Pacific Gas & Electric.
- Les Starck, Director of T&D Business Unit, Southern California Edison.
- Caroline Winn, Director of T&D Asset Management, San Diego Gas & Electric.
- Sean Gallagher, Director of Energy Division, California Public Utilities Commission.
- Steve Ellenbecker, Energy Advisor to Wyoming Governor Freudenthal.
- Jim Bushnell, Research Director, University of California Energy Institute.

Project Schedule

The project was approved and commissioned in October 2006. The TAC workshops were held in January and September 2007. A total of four project briefings at several forums have been made. A briefing at CAISO was held in February 2008.

Project Team

The research project team consists of the Vikram Budhraja, John Ballance, Jim Dyer, and Fred Mobasheri of Electric Power Group, Joseph Eto, Lawrence Berkeley National Laboratory, and Alison Silverstein, Alison Silverstein Consulting. Virgil Rose provided invaluable vision, guidance, and encouragement for this research project.

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Appendix H

Comparison of Electric Transmission

With Gas and Telecommunication Industries

1.0 Introduction

Electric, gas, and telecommunication industries all rely on networks for transport. During the 1990's, there was a tremendous expansion in telecom transport capacity. Also, gas pipeline capacity has generally kept pace with demand as a result of new pipelines or expansion of capacity of existing pipelines.

Electric transmission investments, however, have lagged development in new generation supplies, load growth, and power trading or interregional power transfer volumes. A key policy question that gets asked is, "why do transmission investments lag and are there some lessons from other industries that may inform policymakers with respect to development of new transmission projects, cost allocation, and cost recovery?"

This section provides a comparative assessment of the three industries and summarizes key differences between electricity and the Gas and Telecom industries that have a bearing on development of new capacity, cost allocation, and cost recovery.

2.0 Industry Comparison

All three industries rely on physical networks for transport, with the exception that in the telecom industry where wireless technology is utilized for transmission short distances[105]. The key characteristics of the three networks can be compared in terms of:

- Planning
- Infrastructure Characteristics
- Approvals, Cost Recovery and Rate Making

A comparative summary of the three industries is provided in Table APH- 1.

Table APH- 1. Comparison of gas and telecom with electric transmission

PLANNING	Gas	Telecom	Electricity
Planning for New Projects	Gas pipeline companies	Telecom companies	Utilities, independent transmission companies, ISOs/RTOs, stakeholders
Planning Process	Open season ▪ Market analysis	Commercial decision	Planning and economic studies – resource planning, load flows, economic

105. For this discussion, satellite-based telecommunications is not considered.

	▪ Subscription for capacity		analysis of costs and benefits, stakeholder and regulatory acceptance
Project Justification	Demonstration of public interest, economic feasibility and no significant environmental impact in FERC Filing	Commercial Decision	Review of need, reliability, economics, alternatives, environment impacts – before different state, federal, industry and stakeholder groups
Lead Times	2 - 5 years	1 - 3 years	5 - 10 years
INFRASTRUCTURE CHARACTERISTICS	**Gas**	**Telecom**	**Electricity**
Transport Function	Gas molecules	Voice and data	Electricity
Transport Medium	Pipelines	Fiber, copper, microwave or satellite	Conductors
Amount of Transport Capacity	Known	Known	Variable in an AC network due to parallel flows and lack of flow control
Rated Capacity	Determined by equipment	Determined by equipment.	Determined by studies and approvals by WECC, ISO
Schedules	Yes	Yes	Yes
Flow Control	Yes	Yes	Limited in AC, expensive Yes, for DC lines.
Storage	Yes	No	Limited (pumped storage hydro)
Inadvertent Flows	No	No	Yes
Cost/Mile	$1 to 2 million	Low	$2 to 10 million
User Rights	Contracted firm	Contracted firm	Subject to Open Access Rules
ROW	▪ Negotiated easements or ROW acquisition	Negotiated easements	Negotiated easements or ROW acquisition, (eminent domain for acquisition), designated corridors over

			federal lands
ROW Requirements	▪ Buried or over-land pipelines ▪ Multiple use ▪ Pipelines 16-48” with 40′ clearance for above ground pipes; 5-6 feet underground	▪ Buried or overhead. ▪ Some dedicated use (e.g. MW towers) ▪ Multiple use of gas, railroad or other ROWs	▪ Overhead lines ▪ Specific or dedicated use ▪ 100-300′ wide ROW, access roads, and substations
Approvals, Cost Recovery & Rate Making	**Gas**	**Telecom**	**Electricity**
Approvals for New Projects	▪ FERC ▪ State & local siting	▪ Commercial decision ▪ Some state and local siting	▪ Approvals by ISO, WECC, state and federal regulatory bodies ▪ Environmental approvals – lead agency ▪ Construction permit – utility commissions
Cost Responsibility	Subscription contracts based on open season or owner’s risk	Owner’s risk	Negotiated solution amongst project participants subject to regulatory approvals
Cost Recovery	FERC approved tariff	Market	FERC approved ISO tariff
Rate Making	Cost of service or market	Market	Cost of service

2.1. Planning

In the gas industry, interstate pipeline companies develop plans for new pipelines or expansion of existing pipelines. The need for such facilities is demonstrated through an “open-season” subscription process. Lead times are generally 2– to 5–years and the project justification is generally based on meeting market need as evidenced by subscriptions for capacity.

Telecom industry planning decisions are generally based on individual company commercial decisions and lead times are short ranging from 1– to 3–years.

Electric transmission planning involves multiple levels of review and stakeholder participation. Traditionally, planning was carried out by utilities. Now, the planning function has shifted to

Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs). However, transmission projects may also be planned by new entrants or stakeholders. The planning process now involves utilities, RTOs/ISOs and stakeholders, and ultimately Western Electricity Coordinating Council (WECC) (in the west) for review of proposed transmission project for reliability and to establish a rating. The lead time is 5– to 10–years.

2.2. Infrastructure Characteristics

Gas infrastructure is a system of pipes, valves, and compressor stations. It may also include storage facilities. Pipelines can be as large as 48" in diameter, with required right-of-ways of up to 50 feet. Pipes can be above ground or underground. The physical transport capacity is based on the equipment size – pipe size and compressor stations.

Telecom infrastructure consists of copper, microwave, satellite or fiber lines. The copper and fiber are often buried along existing rights-of-ways of railroad tracks, gas pipelines or other infrastructure (e.g. cables over electric transmission lines). As in the case of gas, the transport capacity for voice and data is fixed based on equipment (for example, number of lit fibers in the case of fiber to transport voice and data). Microwave repeater facilities are typically located at the tops of prominent geographic features, such as mountains, to achieve the greatest distance between repeaters (microwave communication depends on a line-of-sight between repeater stations). In urban areas, repeaters are frequently mounted on towers atop buildings. Satellite antennas may be placed at ground level or on building roofs where clear line-of-sight to the communications satellite is available.

Electric transmission lines require much larger rights-of-ways (100 to 300') and offer limited opportunities for multiple uses. Rights-of-way (ROW) costs are one reason why transmission line costs can be several times greater than gas or telecom for the same distance. In addition, the transport capacity of an AC electric transmission line is often determined by network characteristics and can change as a result of parallel network flows and system configuration.

AC transmission lines also have other major differences compared to the gas and telecom industries – flows are not controlled (except by use of phase shifting transformers and other flow control devices which can be costly), but determined by the physics of the network; transmission delivery capacity is variable; and the use of transmission is subject to open access rules with transmission owner (or contract right holder) being able to use the transmission on the same terms and conditions for access as other market participants.

Federal Energy Regulatory Commission (FERC) is considering long term transmission contracts, but current open access rules provide no certainty of use of transmission to owners. The owner could achieve financial neutrality through use of financial instruments.

2.3. Approvals, Cost Recovery and Rate Making

Gas pipelines require FERC approvals for construction, as well as applicable environmental, local siting and land use permits. FERC review of need is based on "subscriptions" or other equivalent evidence. Cost recovery is based on FERC approved rates including a rate of return component.

Telecom approvals are primarily a commercial decision with some FCC licensing requirements
Transmission projects require approvals by:

• WECC	For compliance with reliability standards and ratings
• Utility	Project sponsor – need and benefits
• ISO (or equivalent)	Planning – need, benefits and alternatives
• Certificate of Public Convenience and Necessity (CPCN)	California Public Utilities Commission (CPUC) or other lead environmental agency
• Tariffs – Cost Recovery	FERC

These different levels of approvals also involve stakeholders and the process can be time consuming, expensive, and uncertain.

A summary of the key differences between Electricity and Gas/Telecom that Impact Cost Allocation and Cost Recovery are presented in Table APH- 2.

Table APH- 2. Key differences between electricity and gas/telecom that impact cost allocation and cost recovery

1. Greater ROW Requirements 2. Higher Cost Per Mile 3. Longer Project Lead Time 4. Uncertain and Changing User Rights 5. Expensive and Limited Flow Control for AC Networks 6. Multiple Layers of Stakeholder Involvement in Planning Process 7. State Jurisdiction Over Transmission Siting 8. Multiple Levels of Approvals – ISO, WECC, State, FERC 9. Eminent Domain Rights of Utilities – results in need to obtain footprint utility support or participation

3.0 ANALYSIS AND CONCLUSIONS

The open season subscription approach used in the gas industry could be used in the electric industry. In a sense, if a new project is proposed and approved by the California ISO for integration into the CAISO system with rolled in rates, it is the equivalent of full subscription by CAISO on behalf of CAISO users. The subscription approach is more directly applicable to DC lines (or AC with flow control). In any event, certainty about cost recovery including a return on investment is key for transmission projects to move forward.

It is unlikely that transmission will be built by investors taking on “commercial risk” as is the case in telecom due to the regulatory and rate approval processes that govern transmission.